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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR AUTHORITY TO CHANGE RATES	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

MAY 18, 2021

TABLE OF CONTENTS

SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-1:

The following questions refer to the Rebuttal Testimony of Charles J. Locke:

Referring to page 5, please state the circumstances when a retail customer can opt to take point-to-point transmission service.

Response No. TIEC 15-1:

The circumstances when a load can take Point-To-Point Transmission Service under the SPP Open Access Transmission Tariff ("SPP Tariff") are described under the definitions of Eligible Customer, Network Load, and Transmission Customer. See these definitions in the SPP Tariff at Part I, Section 1 "E - Definitions," "N – Definitions," and "T - Definitions." Other provisions addressing the manner in which Point-To-Point Transmission Service can be taken include Part II and related schedules and attachments of the SPP Tariff.

Prepared By: Charles J. Locke Title: SPP, Dir Transmission Policy & Rates

Sponsored By: Charles J. Locke Title: SPP, Dir Transmission Policy & Rates

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PUC DOCKET NO. 51415

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-2:

Do the circumstances identified in response to TIEC 15-1 apply to SWEPCO? Please explain why or why not.

Response No. TIEC 15-2:

The SPP Tariff provisions identified in the response to TIEC 15-1 apply to loads connected to the SPP Transmission System, including such loads of SWEPCO.

Prepared By: Charles J. Locke	Title: SPP, Dir Transmission Policy & Rates
Sponsored By: Charles J. Locke	Title: SPP, Dir Transmission Policy & Rates

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-3:

The following questions refer to the Rebuttal Testimony of Charles J. Locke:

Referring to page 6, please provide all documents where FERC has stated that Order Nos. 888 and 890 apply specifically to retail customers that purchase bundled transmission service from a regulated utility that provides transmission service.

Response No. TIEC 15-3:

SPP has not performed this research.

Prepared By: Charles J. Locke Title: SPP, Dir Transmission Policy & Rates

Sponsored By: Charles J. Locke Title: SPP, Dir Transmission Policy & Rates

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-4:

The following questions refer to the Rebuttal Testimony of Gregory S. Wilson:
Referring to page 2, please confirm that the only empirical evidence supporting Mr. Wilson's cost-benefit analysis are the analyses discussed on lines 9 through 16. If not, please provide all other empirical evidence supporting Mr. Wilson's cost benefit analysis.

Response No. TIEC 15-4:

All empirical evidence supporting Mr. Wilson's analysis is included in his direct testimony. The list cited in this question is not intended to be all-inclusive.

Prepared By: Gregory S. Wilson Title: VP & Principal, Lewis & Ellis, Inc.

Sponsored By: Gregory S. Wilson Title: VP & Principal, Lewis & Ellis, Inc.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-5:

The following questions refer to the Rebuttal Testimony of Gregory S. Wilson:
Referring to page 2, lines 9-16, please confirm that the analyses Mr. Wilson listed in this answer do not compare the cost of self-insurance against the cost of commercial insurance. If not, please explain in detail how the listed analyses
compare the cost of self-insurance against the cost of commercial insurance, and provide the cost of commercial insurance that is used in the listed analyses.

Response No. TIEC 15-5:

Confirmed. The listed items are only part of Mr. Wilson's analysis, and were never intended to be a complete rehash of his original testimony. The comparison of the cost of self-insurance versus commercial insurance is included in Mr. Wilson's direct testimony.

Prepared By: Gregory S. Wilson Title: VP & Principal, Lewis & Ellis, Inc.

Sponsored By: Gregory S. Wilson Title: VP & Principal, Lewis & Ellis, Inc.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-6:

The following questions refer to the Rebuttal Testimony of Dylan W. D'Ascendis:
Referring to pages 80-83, please identify all commission proceedings in which Mr. D'Ascendis's size adjustment was adopted.

Response No. TIEC 15-6:

In Mr. D'Ascendis' experience, most Commission Orders are silent on results of individual models and certainly on aspects of individual models, including the adoption of size adjustments in authorized ROE values. With this in mind and with the knowledge that Mr. D'Ascendis has not performed an exhaustive review of all past state regulatory commission decisions, he is aware that in the proceedings noted in the table below the Pennsylvania Public Utility Commission acknowledged the increased risk associated with an electric utility's small size when setting the authorized ROE at the top end of the range of DCF results.

Company	**PA PUC Docket No.**	**Date of Final Order**
Citizen's Electric Company of Lewisburg, PA	R-2019-3008212	April 27, 2020
Valley Energy, Inc.	R-2019-3008209	April 27, 2020
Wellsboro Electric Company	R-2019-3008208	April 27, 2020

Mr. D'Ascendis is also aware that on May 2, 2018, in Docket No. 2017-292-WS, concerning Carolina Water Service, Inc., the Public Service Commission accepted Mr. D'Ascendis' entire position regarding the cost of capital, including the use of a size adjustment.

Prepared By: Dylan D'Ascendis Title: Director, ScottMadden, Inc.

Sponsored By: Dylan D'Ascendis Title: Director, ScottMadden, Inc.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-7:

The following questions refer to the Rebuttal Testimony of Dylan W. D'Ascendis:
Referring to page 84, please identify all commission proceedings in which Mr. D'Ascendis's credit risk adjustment was adopted.

Response No. TIEC 15-7:

In Mr. D'Ascendis' experience, most Commission Orders are silent on results of individual models and certainly on aspects of individual models, including the adoption of credit risk adjustments in authorized ROE values. In cases that Mr. D'Ascendis has been a party to as the expert in the proceeding, to his knowledge, each Commission Order has been silent on the subject of the credit risk adjustment and its applicability to their decisions.

Prepared By: Dylan D'Ascendis	Title: Director, ScottMadden, Inc.
Sponsored By: Dylan D'Ascendis	Title: Director, ScottMadden, Inc.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-8:

The following questions refer to the Rebuttal Testimony of Dylan W. D'Ascendis:
Referring to pages 90-91, for each of the journal articles listed in footnotes 149 through 152:

a. Please state the number of citations the article has (i.e., the number of times the article has been cited).
b. Please provide a list of the citing articles.
c. Please provide a link where the article can be publicly accessed.

Response No. TIEC 15-8:

a. Please see TIEC 15-8 Attachment A for a list of citations for each article from Google Scholar. This list is incomplete as it omits practitioner citations as well as citations from legal proceedings. For example, Mr. D'Ascendis has cited these articles in numerous testimonies before regulatory bodies, and Google Scholar lists none these citations.
b. In addition, the number of citations for each article does not dilute the fact that each of these articles were peer-reviewed and accepted for publication to these journals. Furthermore, none of the articles referenced by TIEC in this request have been rebutted in the academic literature.
c. Please refer to the attachment and Mr. D'Ascendis' response to TIEC's 15th, Q. # 15-8-a. Please see a list of associated links for each article below.

Eugene A. Pilotte, and Richard A. Michelfelder, Treasury Bond Risk and Return, the Implications for the Hedging of Consumption and Lessons for Asset Pricing, Journal of Economics and Business, June 2011. https://www.sciencedirect.com/science/article/abs/pii/S0148619511000415

Richard A. Michelfelder, Empirical Analysis of the Generalized Consumption Asset Pricing Model: Estimating the Cost of Capital, Journal of Economics and Business, April 2015. https://www.sciencedirect.com/science/article/abs/pii/S0148619515000193

Pauline M. Ahern, Frank J. Hanley, and Richard A. Michelfelder, New Approach to Estimating the Equity Risk Premium for Public Utilities, The Journal of Regulatory Economics, December 2011. https://link.springer.com/article/10.1007/s11149-011-9160-5

Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, and Frank J. Hanley, Comparative Evaluation of the Predictive Risk Premium Model, the Discounted Cash Flow Model and the Capital Asset Pricing Model for Estimating the Cost of Common Equity, The Electricity Journal, April 2013. https://www.sciencedirect.com/science/article/abs/pii/S1040619013000845

Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, Decoupling, Risk Impacts and the Cost of Capital, The Electricity Journal, January 2020. https://www.sciencedirect.com/science/article/abs/pii/S1040619019303021

Richard A. Michelfelder, Pauline M. Ahern, and Dylan W. D'Ascendis, Decoupling Impact and Public Utility Conservation Investment, Energy Policy, April 2019. https://www.sciencedirect.com/science/article/abs/pii/S0301421519302423#:~:text=Decoupling%20may%20increase%20or%20decrease,common%20equity%20capital%20and%20risk.&text=Policy%20recommendation%20for%20regulation%20is,of%20return%20due%20to%20decoupling

Prepared By: Dylan D'Ascendis   Title: Director, ScottMadden, Inc.

Sponsored By: Dylan D'Ascendis   Title: Director, ScottMadden, Inc.

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Empirical analysis of the generalized consumption asset pricing model: Estimating the cost of capital

RA Michelfelder - Journal of Economics and Business, 2015 - Elsevier
Other than the problematic discounted cash flow and capital asset pricing models that have been used for decades, no other asset pricing models have generally been adopted for estimating the cost of common equity capital. A recently developed and promising general
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Public utility beta adjustment and biased costs of capital in public utility rate proceedings

RA Michelfelder, P Theodossiou - The Electricity Journal, 2013 - Elsevier
The Capital Asset Pricing Model (CAPM) is commonly used in public utility rate proceedings to estimate the cost of capital and allowed rate of return. The beta in the CAPM associates risk with estimated return. However, an empirical analysis suggests that the commonly used
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Valuing Commercial Finance Companies

DE Coit - 2016 - scholarworks waldenu edu
Stakeholders are increasingly insistent that companies increase firm value. The problem is that stakeholders of financial services firms are unable to accurately determine firm value The purpose of this correlational study was to examine the accuracy of 4 valuation models in
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An empirical analysis of the fiscal incidence of renewable energy support in the European Union

L Haar - Energy Policy, 2020 - Elsevier
In liberalised energy markets, electricity from Renewable Energy (RE) using Solar PV and Wind Turbines requires financial support because the expected number of generation hours is insufficient to induce private investment Such support has a direct cost from the additional ..
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Defining the tariff burden when providing the housing and utilities services in Ukraine

I Balatskyi, V Lavryk - Public and Municipal Finance, 2019 - businessperspectives org
The article is devoted to studying the impact of different social and economic indicators on defining the population's tariff burden for housing and utilities services The article analyzes the housing and utilities services provision system in Ukraine. It is noted that the majority of .
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Positive reinforcement is just the beginning: Associative learning principles for energy efficiency and climate sustainability

SM Schneider, A Sanguinetti - Energy Research & Social Science, 2021 - Elsevier
A major cause of global climate change, human behavior has long been recognized as an essential part of the solution as well Behavior change methods in turn rely in part on associative learning principles Some learning principles, such as positive reinforcement ...
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Searching for key sources of goodwill creation as new global managerial challenge

T Kliestik, M Kovacova, I Podhorska .. - Polish Journal of , 2018 - yadda.icm edu.pl

Prestige, reputation, brand, image simply "enterprise goodwill" as an economic phenomenon has attracted attention of economic experts since the nineteenth century. Even though there are many various methodologies and approaches, its evaluation and

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An analysis of investments by multilateral development banks in Central America

J Lopez Rojas - 2016 - scholarworks waldenu edu

Multilateral development banks (MDBs) are under increased pressure to justify their allocation of donor resources. These funds help produce growth in developing regions such as Central America (CA), where wealth inequality limits individuals' access to basic services ..

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Decoupling impact and public utility conservation investment

RA Michelfelder, P Ahern, D D'Ascendis - Energy Policy, 2019 - Elsevier

Public utilities and regulators are implementing various forms of regulatory mechanisms that decouple revenues from commodity sales to remove a disincentive or create an incentive for utilities to invest in and encourage consumers to conserve electricity, natural gas and water . .

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On the Differential Analysis of Enterprise Valuation Methods as a Guideline for Unlisted Companies Assessment (I): Empowering Discounted Cash Flow Valuation

G Vayas-Ortega, C Soguero-Ruiz JL Rojo-Álvarez - Applied Sciences, 2020 - mdpi com

Abstract The Discounted Cash Flow (DCF) method is probably the most extended approach used in company valuation, its main drawbacks being probably the known extreme sensitivity to key variables such as Weighted Average Cost of Capital (WACC) and Free

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A Study on Factors Influencing Mutual Fund Portfolio Performance: US Equity Market During 2011-2016

M Mekonnen, R Mayer, WW Chien - International Journal of 2018 - igi-global com

Mutual fund portfolio managers do not always meet performance expectations, resulting in loss of capital reserves Out of 3,612 US based open-ended mutual funds, the risk-adjusted performance of 2,890 (80%) failed to meet the S&P 500 performance between the year 2006 .

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Evaluation of capital cost: long run evidence from manufacturing sector

M Markauskas, A Saboniene - Engineering Economics, 2020 - inzeko ktu lt

The article is directed to determine the most appropriate method for evaluating cost of capital of a manufacturing sector and, using the methodology, to perform a case study of Lithuanian manufacturing sector. For evaluation of cost of capital, calculation of Weighted Average

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Promoting Entrepreneurship Education Through Valuation of Cost of Equity

O Oni, PS Mahlangu - Reshaping Entrepreneurship Education With , 2021 - igi-global com

This chapter provided an extensive discussion on promoting entrepreneurship education using capital asset pricing model (CAPM) and Gordon dividend discount Model in the valuation of cost of equity. Researchers have debated on the valid model for valuation cost

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Relationship between Mutual Fund Type, Portfolio Turnover, Longevity, Management Turnover, and Performance

MG Mekonnen - 2017 - scholarworks.waldenu edu

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PROPUESTA DE UN DISEÑO DE PLANTA PARA EL PROCESO DE PRODUCCIÓN DEL IMPERMEABILIZANTE DE CUBIERTA MÁSTIQUE ASFÁLTICO CON ...

DRR Vega - 2017 - cefas umcc cu

El presente trabajo propone un diseño de planta para la producción de impermeabilizante de cubierta basado en Mástique Asfáltico con Polímero que permite satisfacer la demanda de dicho producto en la provincia de Matanzas. Para establecer el diseño de la planta se .

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Valore pubblico e società partecipate: tendenze evolutive della performance

A Ziruolo - 2016 - francoangeli.it
La creazione del valore è un tema che da sempre affascina gli studiosi di ogni ramo delle discipline economiche ed aziendali, che si sforzano di indagarlo da molteplici ed a volte perfino confliggenti punti di vista. Tutto ciò diventa questione ancora più complessa quando ..
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Jointly estimating jump betas

V Polimenis, I Papantonis - The Journal of Risk Finance, 2014 - emerald.com
Purpose–This paper aims to enhance a co-skew-based risk measurement methodology initially introduced in Polimenis, by extending it for the joint estimation of the jump betas for two stocks Design/methodology/approach–The authors introduce the possibility of
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Public utilities and regulators are implementing various forms of regulatory mechanisms that decouple revenues from commodity sales to remove a disincentive or create an incentive for utilities to invest in and encourage consumers to conserve electricity, natural gas and water
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The cost of equity capital in a regulatory environment: an international comparison

KS Graham - 2015 - open.uct.ac.za
South Africa's electricity tariff determinations have been a matter of much public debate. This has been highlighted in popular media in South Africa, with above inflation increases in electricity tariffs allowed by the National Energy Regulator of South Africa (NERSA) in Multi ..
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RA Michelfelder - Journal of Sustainable Finance & Investment, 2014 - Taylor & Francis
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Estimating the conditional equity risk premium in African frontier markets

F Othieno, N Biekpe - Research in International Business and Finance, 2019 - Elsevier
This paper estimates the forward-looking coefficients of risk aversion and the equity risk premia in frontier equity markets in Africa Applying the Bilinear GARCH (BGARCH) in the consumption-based asset pricing framework, we link the stochastic discount factor to ...
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A Case for using a Real Asset Transaction Approach for Estimating the Cost of Capital from Rural Telephone Company Data

V Glass - Journal of Business and Economic Studies, 2018 - jbes.scholasticahq.com
This paper develops a real asset transaction approach for estimating the cost of capital for rural telephone companies whose financial assets are not publicly traded. The transaction approach uses the actual purchase prices of rural local exchange carriers ...
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L'impatto dei sistemi di pianificazione e controllo sui percorsi di risanamento delle società partecipate pubbliche. Potenzialità e limiti alla luce della "riforma Madia"
G Carrano - 2017 - elea unisa it
Il presente lavoro di ricerca ha come oggetto il processo di cambiamento che ha caratterizzato le società partecipate pubbliche negli ultimi anni, focalizzando precisamente la propria attenzione su quanto previsto dal decreto legislativo 175/2016 Testo Unico in .
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PM Ahern, FJ Hanley, RA Michelfelder - Journal of Regulatory Economics, 2011 - Springer
The regulatory process for setting public utilities' allowed rate of return on common equity has generally used the Gordon DCF, CAPM and Risk Premium specifications to estimate the cost of common equity. Despite the widely known problems with these models, there has

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-9:

Referring to page 92-93, please identify all commission proceedings in which Mr. D'Ascendis's Predictive Risk Premium Model was adopted.

Response No. TIEC 15-9:

In Mr. D'Ascendis' experience, most Commission Orders are silent on results of individual models and certainly on aspects of individual models (PRPM is used in portions of the risk premium model and capital asset pricing model applied to both the utility and the non-utility group).
While Mr. D'Ascendis has not performed an exhaustive review of all past state regulatory commission decisions, he is aware that on May 2, 2018, in Docket No. 2017-292-WS, concerning Carolina Water Service, Inc., the Public Service Commission accepted Mr. D'Ascendis' entire position regarding the cost of capital, including the use of the Predictive Risk Premium Model.

Prepared By: Dylan D'Ascendis	Title: Director, ScottMadden, Inc.
Sponsored By: Dylan D'Ascendis	Title: Director, ScottMadden, Inc.

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH SET OF REQUESTS FOR INFORMATION

Question No. TIEC 15-10:

The following question refers to the Rebuttal Testimony of Michael A. Baird:
Referring to pages 40-41, when did the SPP first start providing capacity accreditation for wind resources?

Response No. TIEC 15-10:

See TIEC 15-10 Attachment 1, a copy of the SPP criteria effective July 25, 2006, which includes provisions for capacity accreditation for wind resources. Within the attached, the pages containing accreditation provisions for wind resources indicates these provisions were effective April 25, 2006.

Prepared By: C. Richard Ross	Title: Dir Trans RTO Policy
Sponsored By: C. Richard Ross	Title: Dir Trans RTO Policy

SPP Southwest Power Pool

Southwest Power Pool

CRITERIA

LATEST REVISION: July 25, 2006

APPENDICES

Southwest Power Pool
CRITERIA

FOREWORD

All members of Southwest Power Pool (SPP) adopted the NAPSIC (now North American Electric Reliability Council or NERC) Operating Guides on March 11, 1970. Over the years, these documents have developed into policies, procedures, principles, criteria, standards and guides. In some instances, the NERC documents are not in sufficient detail to meet specific needs of SPP. Additional necessary details have been adopted by SPP as Criteria. This Criteria is considered as the policies, standards or principles of conduct by which the coordinated planning and operation of the interconnected electric system is achieved. Reference to SPP in terms of responsibilities for activities means SPP organizational groups which are defined in SPP Bylaws and the SPP Directory Reference to the SPP bulk electric system means the combined interconnected electric systems of members. Reliability Coordination (Coordinator) and Security Coordination (Coordinator) are used interchangeably in this Criteria.

INTRODUCTION

A primary purpose of SPP is to facilitate joint planning and coordination in the construction and operation of the generation and transmission network of the individual members so as to provide for increased operating efficiency and continuing service reliability, both in SPP and the contiguous regions. To assist in achieving these objectives, the members of SPP recognize that common criteria and procedures must be used in the planning and operation of the combined electric system for cost effective, adequate and reliable bulk power supply This Criteria presents the characteristics of a well-planned bulk power electric system, describes the basis for model testing and lists the reliability and adequacy tests to be used to evaluate the performance of the SPP bulk electric system, and describes coordinated operating procedures necessary to maintain a reliable and efficient electric system. Reliable operation of the interconnected bulk electric system of SPP requires that all members comply with this minimum Criteria. Compliance with this Criteria is considered essential to a well planned and operated electric system, and is mandatory for all SPP members. Adherence can be expected to provide adequate and effective safeguards against the occurrence of uncontrolled area-wide power disturbances and will also provide efficient utilization of the electric system resources. This Criteria is also intended to serve as a guideline for developing more specific and definitive criteria by each member of SPP.

It is the policy of SPP to maintain as high an interconnection capability with adjoining regions as is economically prudent. Interconnections with adjoining regions shall be designed such that SPP will remain interconnected following all of the more probable transmission and generation outage contingencies. Emergencies that occur in adjoining regions can affect SPP, just as the emergencies within SPP can affect adjoining regions Therefore, joint studies shall be made on a regular basis to investigate various system emergencies that can occur and their effects on the electric system. In this way, the effectiveness of existing and planned interconnections shall be periodically measured and the design of the system periodically updated so that the interconnection capability and reliability shall be maintained.

1.0 LOAD AND ENERGY FORECASTS

Each member shall provide annually to the SPP Office a 10-year forecast of peak demand and net energy requirements. This information is to conform with requirements set by SPP in conjunction with NERC and government agencies The forecasts so provided shall be produced in accordance with generally recognized methodologies and also in accordance with the following principles.

a. Each member shall select its own load forecasting methodology and establish its own load forecast.

b. Each member shall forecast load based on expected weather conditions.

c. Method used, factors considered and assumptions made shall be submitted along with the forecast.

d. The SPP forecast shall be the total of the member forecasts.

e. High and low growth rate and extreme weather scenario bands shall be produced for the SPP Regional and Subregional demand and energy forecasts.

f. Economic, technological, sociological, demographic and any other significant factors shall be considered in producing the forecast.

2.0 CAPACITY MARGIN

This Criteria requires and provides for the sharing of reserve generating capacity as a means of reducing capacity requirements of each Member and providing reliable electric service to firm customers due to the equitable purchase, sale and exchange of generating capacity among Members.

2.1 Definitions

2.1.1 Load Serving Member

A Load Serving Member shall mean any SPP Member assuming legal obligation to provide firm electric service to a customer or group of customers within SPP.

2.1.2 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i e , power for which the seller assumes the obligation to provide capacity (including SPP defined Capacity Margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load. Power purchased shall only be considered to be Firm Power if Firm Transmission Service is in place to the Load Serving Member for delivery of such power Firm Power does not include "financially firm" power.

2.1.3 System Capacity

A Load Serving Member's System Capacity shall be equal to the capability of its generating facilities, including its ownership share of jointly owned units, demonstrated under procedures set forth in SPP Rating of Generating Equipment Criteria, adjusted to reflect the purchase from and/or sale to any other party of generating capacity or SPP defined Operating Reserve, under any appropriate agreement. For purchases and sales, the contract amount governs regardless of the amount actually delivered at the time of such Load Serving Member's greatest Net Load. Capacity purchases shall only be considered if Firm Transmission Service is in place to the Load Serving Member for delivery of power from such capacity.

Unless reported separately, generating facilities owned by others within the Load Serving Member's system that are obligated to furnish firm power to customers within the Load Serving Member's system shall also be reported. Absent any bilateral contractual arrangements with the host Control Area, the host Control Area will not be required to be responsible for capacity and/or reserve requirements. The reporting of generating facilities owned by others does not constitute an obligation on the Load Serving Member's part to furnish reserves or back up power for that generation.

2.1.4 Net Load

The term Net Load for any Load Serving Member shall mean, for any clock hour:

(a) Net generation by the Load Serving Member's facilities; plus

(b) Net receipts into the Load Serving Member's system; minus

(c) Net deliveries out of such Load Serving Member's system

Unless reported separately, the Net Load of other non-Load Serving Members located within the Load Serving Member's system shall also be reported Absent any bilateral contractual arrangements, the reporting of these loads does not constitute an obligation on the Load Serving Member's part to furnish reserves, back up power, or incur financial obligations from SPP for that load.

2.1.5 Capacity Year

Capacity Year shall mean a period of twelve consecutive months beginning on October 1 of each calendar year. Any period less than a Capacity Year shall be designated as Short Term.

2.1.6 System Peak Responsibility

System Peak Responsibility of a Load Serving Member for any Capacity Year shall mean the Load Serving Member's greatest Net Load during that Capacity Year plus:

(a) The contract amount of Firm Power sold to others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the sale of a specified amount of Firm Power; and minus

(b) The contract amount of Firm Power purchased from others under agreements in effect as of the time of such Load Serving Member's greatest Net Load which provide for the purchase of a specified amount of Firm Power.

In each case, the contract amount governs regardless of the amount actually delivered at the time of a Load Serving Member's greatest Net Load.

2.1.7 Capacity Margin

Capacity Margin shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Peak Responsibility.

2.1.8 Percent Capacity Margin

Percent Capacity Margin shall be defined by the formula:

Percent Capacity Margin = (Capacity Margin/System Capacity) x 100

2.1.9 Minimum Required Capacity Margin

Each Load Serving Member's Minimum Required Capacity Margin shall be twelve percent. If a Load Serving Member's System Capacity for a Capacity Year is comprised of at least seventy-five percent hydro-based generation, then such Load Serving Member's Minimum Required Capacity Margin for that Capacity Year shall be nine percent.

2.1.10 System Capacity Responsibility

A Load Serving Member's System Capacity Responsibility for any Capacity Year shall mean the sum of that Load Serving Member's System Peak Responsibility and its Minimum Required Capacity Margin.

2.1.11 Capacity Balance

Capacity Balance shall mean the amount by which a Load Serving Member's System Capacity exceeds its System Capacity Responsibility.

2.1.12 Firm Transmission Service

Firm Transmission Service is that service defined in any applicable transmission service provider tariff.

2.2 Capacity Responsibility

(a) Each Capacity Year, each Load Serving Member shall possess System Capacity at least equal to its System Capacity Responsibility.

(b) Prior to the establishment of its System Peak Responsibility for each Capacity Year, each Load Serving Member shall provide System Capacity by one or more of the following means:

(i) Establishing a unit rating consistent with SPP generating equipment rating Criteria, prior to establishing its System Peak Responsibility;

(ii) Reducing its System Peak Responsibility by purchase of Firm Power from any Member or non-Member by separate agreement;

(iii) Separate written agreement with another Member or a non-Member for purchase of a specified amount of capacity; and/or

(iv) Reducing its Net Load.

(c) A Load Serving Member may purchase Short Term capacity to provide a part of its System Capacity or Short Term Firm Power to reduce its System Peak Responsibility subject to each of the following restrictions:

(i) Such Short Term period shall not be less than four consecutive months, and shall include the day the Load Serving Member establishes its System Peak Responsibility. Such period shall begin during May 1 to June 1 or November 1 to December 1;

(ii) The amount of Short Term capacity or Short Term Firm Power purchased shall not exceed 25% of the Load Serving Member's System Peak Responsibility; and

(iii) The Load Serving Member shall purchase such Short Term Capacity or Short Term Firm Power prior to the start of the Short Term period.

(d) A Load Serving Member may sell Short Term Capacity or Short Term Firm Power from resources comprising its Capacity Balance, provided that its System Capacity Responsibility is met.

2.3 Records

Each Load Serving Member, upon request, shall provide accurate and detailed records of information related to this Criteria to the SPP Staff. Except for System Peak Responsibility, all other information shall be provided prior to establishing System Peak Responsibility for a Capacity Year and shall include; validation of System Capacity per SPP Rating of Generating Equipment Criteria, Capacity purchase and sale contracts, Firm Power purchase and sale contracts, and firm transmission service agreements. The SPP Staff shall verify information supplied by each Load Serving Member. Calculations shall be based on the highest peak load of each of the Load Serving Members during the Capacity Year. All capacity and demand values will be rounded to the nearest whole MW for purposes of this Criteria. All data submitted to SPP related to this Criteria shall be considered confidential by the SPP Staff and shall not be released in any form except by force of law.

2.4 Generation Planning

2.4.1 Design Features

a. In order to maintain a balanced design of the electric system, excessive concentration of generating capacity in one unit, at one location, or in one area shall be avoided.

b. Auxiliary power sources shall be provided in each major generating station to provide for the safe shutdown of all the units in the event of loss of external power.

c. In each major load area of SPP, a unit capable of black start shall be provided having the capability of restarting the other units in the area.

d. Boiler controls and other essential automation of major generating units shall be designed to withstand voltage dips caused by system short circuits.

2.4.2 Fuel Supply

Assurance of having desired generating capacity depends, in part, on the availability of an adequate and reliable fuel supply. Where contractual or physical arrangements permit curtailment or interruption of the normal fuel supply, sufficient quantities of standby fuel shall be provided. Due to the dependence of hydroelectric plants on seasonal water flows, this factor shall be taken into consideration when calculating capacity for capacity margin requirements.

3.0 REGIONAL TRANSMISSION PLANNING

3.1 Concepts

The interconnected transmission system should be capable of performing reliably under a wide variety of expected system conditions while continuing to operate within equipment and electric system thermal, voltage, and stability limits. Electric systems must be planned to withstand contingencies and maintenance outages. Extreme event contingencies which measure the robustness of the electric systems should be evaluated for risks and consequences. The *NERC Planning Standards* define specific requirements that provide a high degree of reliability for the large interconnected electric system. SPP provides additional coordinated regional transmission planning requirements to promote reliability through this Criterion and related "Coordinated Planning Procedures" in the *SPP Open Access Transmission Tariff.*

3.2 Definitions

NERC (NAERO – North American Electric Reliability Council (North American Electric Reliability Organization) – An organization of all segments of the electric industry that recommends, sets, oversees, and implements policies and standards to ensure the continued reliability of North America's interconnected electric grids.

Nominal Voltage – The root-mean-square, phase-to-phase voltage by which the system is designated and to which certain operating characteristics of the system are related. Examples of nominal voltages are 500 kV, 345 kV, 230 kV, 161 kV, 138 kV, 115 kV and 69 kV.

3.3 Coordinated Planning

SPP members operate in a highly interconnected system and shall coordinate transmission planning. This coordination shall include voluntary efforts between interconnected SPP members and non-members. SPP will be the primary responsible party for coordinated transmission planning.

The planning and development of transmission facilities will be coordinated with neighboring systems to preserve the reliability benefits of interconnected operations. The transmission systems should be planned to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation

3.3.1 Planning Criteria

Individual members may develop Planning Criteria that shall, at a minimum, conform to *NERC Planning Standards* and SPP *Criteria*. Individual member Criteria shall consider the following:

- **a.** Excessive concentration of power being carried on any single transmission circuit, multi-circuit transmission line, or right-of-way, as well as through any single transmission station shall be avoided.
- **b.** Intra-regional inter-regional, and trans-regional power flows shall not result in excessive risk to the electric system under normal and contingency conditions as outlined in this criteria.
- **c.** Switching arrangements shall be planned to permit effective maintenance of equipment without excessive risk to the electric system.
- **d.** Switching arrangements and associated protective relay systems shall be planned to not limit the capability of a transmission path to the extent of causing excessive risk to the electric system.
- **e.** Sufficient reactive capacity shall be planned within the SPP electric system at appropriate places to maintain transmission system voltages within plus or minus 10% of nominal on load serving buses or as determined by the transmission owner and user under contingency conditions.
- **f.** Facilities shall be rated as assigned in *SPP Criteria* section 12.

3.3.2 Planning Assessment Studies

Individual transmission owners shall perform individual transmission planning studies and shall cooperate in SPP and Inter-Regional studies. These planning studies are for the purposes of identifying any planning criteria violations that may exist and developing plans to mitigate such violations Members shall contact the Transmission Working Group whenever new facilities are in the conceptual planning stage so that optimal integration of any new facilities and potentially benefiting parties can be identified. Studies affecting more than one system owner or user will be conducted on a joint system basis. Reliability studies will examine post-contingency steady-state conditions as well as stability, overload, cascading, and voltage collapse conditions. Updates to the transmission assessments will be performed, as appropriate, to reflect anticipated significant changes in system conditions.

3.3.3 Benchmark SPP Models

SPP staff will benchmark model data against actual SPP system conditions (e.g., generation dispatch, load, and load power factor) which correspond to the time frames for which the models are created. As a minimum the results will be reported semiannually.

3.4 Transmission Contingency

The transmission system of the SPP region shall be planned and constructed so that the contingencies as set forth in the Criteria will meet the applicable *NERC Planning Standards* for System Adequacy and Security – Transmission System Table I (hereafter referred to as NERC Table I) and its applicable standards and measurements. Extreme contingency evaluations will be conducted to measure the robustness of the transmission systems and to maintain a state of preparedness to deal effectively with such events. Although it is not practical to construct a system to withstand all possible extreme contingencies without cascading, it is desirable to understand the risks and consequences of such events and to attempt to limit the significant economic and social impacts that may result.

3.4.1 Adequacy

3.4.1.1 Base Case

The Model Development Working group (MDWG) will assemble and verify base case models. These models will maintain at least the following:

- System facilities shall be modeled to reflect normal operation.
- Line and equipment loading shall be within applicable thermal rating limits.
- Voltage levels shall be maintained within applicable limits.
- All customer demands shall be supplied, and all contracted firm (non-recallable reserved) transfers shall be maintained.
- Stability (dynamic and steady state) of the network shall be maintained.
- Cascading outages shall not occur.

The MDWG shall work with the Transmission Working Group (TWG) to resolve issues not considered data errors.

3.4.1.2 Loss of Single Component

The MDWG will run contingency studies under the following:

- Initiating incident results in a single element out of service.
- Line and equipment loadings shall be within applicable rating limits.
- Voltage levels shall be maintained within applicable limits as specified in 3.3.1e.
- No loss of customer demand (except as noted in NERC Table I, Footnote b), nor the curtailment of contracted firm (non-recallable reserved) transfers shall be required.
- Stability (angular and voltage) of the network shall be maintained.
- Cascading outages shall not occur.

3.4.1.3 Loss of Two or More Components

The MDWG will run contingency studies under the following:

- Initiating incident may result in two or more (multiple) components out of service.
- Line and equipment loadings shall be within applicable thermal rating limits.
- Voltage levels shall be maintained within applicable limits as specified in 3.3.1e.
- Stability (angular and voltage) of the network shall be maintained.
- Planned outages of customer demand or generation (as noted in NERC Table I) may occur, and contracted firm (non-recallable reserved) transfers may be curtailed.
- Cascading outages shall not occur.

3.4.1.4 Extreme Event

The TWG will run contingency studies where extreme contingency events could lead to uncontrolled cascading outages or system instability. The TWG shall document the measures and procedures to mitigate or eliminate the extent and effects of those events and may at their discretion recommend such measures and procedures

3.4.2 Study Requirements

System contingency studies should be based on system simulation models that should incorporate:

- Evaluation of reactive power resources,
- Existing protection systems, and

- Any existing backup or redundancy protection systems.

These studies will assist to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in appropriate Category of NERC Table I.

Studies will consider all contingencies applicable to the appropriate Category, but will evaluate only the most critical, and document the selection rationale. Studies will be conducted or reviewed annually, shall cover seasonal or expected critical system conditions for near (current or next year) and intermediate (two to five year recommended) planning horizons, and address both intra- and interregional reliability. Detailed analyses of the systems will not be conducted annually if changes to system conditions do not warrant such analyses

The longer-term (beyond five years) simulations will identify concerns that may surface in the period beyond the more certain intermediate year period. Focus of simulations for the longer term will be on marginal system conditions evident from the intermediate year cases. Cases beyond the five-year horizon will be evaluated as needed to address identified marginal conditions.

3.4.3 Mitigation Plans

When simulations indicate an inability of the systems to respond as prescribed by this Criterion, responsible entities must provide a written summary of their mitigation plans, including a schedule for implementation, to achieve the required system performance throughout the planning horizon. Mitigation plan summaries should discuss expected required in-service dates of facilities, should consider lead-times necessary to implement plans, and will be reviewed for continuing need in subsequent annual assessments.

3.4.4 Reporting Requirements

Entities responsible for the reliability of interconnected transmission systems shall report annually on the performance of their systems in connection with NERC *Planning Standard* I.A.S1 to the SPP Region. The SPP will annually provide a summary of intra- and interregional studies to the NERC Adequacy Committee (RAS). Regional and interregional reliability assessments shall include the results of the system simulation testing as stated in this Standard I.A

3.5 Protective Relaying, Monitoring And Controls

Protective relaying, communications and instrumentation play an important role in maintaining the reliability of the bulk electric system. Protective Relay Systems (PRS) requirements shall be taken into account during the planning and design of generation, transmission and substation configurations. If configurations are proposed that require PRS that do not conform to this criteria or to accepted IEEE/ANSI practice, then the entities affected shall negotiate a solution. The principles for planning additions in these categories are set forth in this Criteria.

a. The bulk power protective relay system design shall have as its objective rapid clearing of all faults, with no fault permitted to remain uncleared despite the failure of any single protective system component. To accomplish this, transmission protection systems shall be installed as specified in Transmission Protection Systems Criteria 7.2.

b. Control areas shall maintain communications systems to their generating stations, operation centers and to neighboring utilities which shall provide adequate communication in the event of failure of any one element of the systems. In general, such communication systems should not be susceptible to failure during an interruption of the A.C power supply in any part or all of their areas.

c. Loadings on the bulk electric system shall be monitored continually to insure that operation is within safe limits.

d. Suitable instrumentation, and/or other devices, shall be installed to measure appropriate quantities at key points in the electric system with appropriate automatic alarms

e. Fault recording devices as described in Criteria 7.1 shall be installed at appropriate points within the SPP region so that outages and short circuits can be analyzed and protective relay performance studied. In addition, Disturbance Monitoring Equipment shall be provided to meet Criteria 7.1 so that system disturbances may be analyzed.

f. Underfrequency Load Shedding equipment shall be installed pursuant to Criteria 7 3 for the purpose of maintaining a stable operating frequency.

g. As specified in Criteria 7 4, Special Protection Systems when installed shall detect abnormal system conditions and take pre-planned, coordinated, corrective action to provide acceptable system performance.

h. When Undervoltage Load Shedding equipment is installed by a member system as specified in Criteria 7.5 for the purpose of stabilizing interconnected systems and mitigating the effects of voltage collapse, then this program shall coordinate with all other schemes of which include system protection, Underfrequency Load Shedding, Automatic Restoration of Load and Generation Control and Protection.

i. Given the requirements of Criteria 7.6, Automatic Restoration of Load schemes may be installed by member systems to expedite load restoration. These systems shall be coordinated with all other schemes such as system protection, Underfrequency Load Shedding, Undervoltage Load Shedding, and Generation Control and Protection. These systems shall operate only after underfrequency and/or undervoltage events.

j. Generation Control and Protection schemes shall be designed pursuant to Criteria 7.7 to provide a reasonable balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect generator equipment from damage.

4.0 REGIONAL CALCULATION OF AVAILABLE TRANSFER CAPABILITY

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners. This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes. Likewise, when Transmission Owners calculate ATC, they are responsible to coordinate the ATC between their areas. If there is a dispute concerning the ATC, the SPP Transmission Working Group (TWG) will act as the technical body to determine the ATC to be reported.

This Criteria provides Transmission Owners and the SPP Transmission Provider flexibility to revise the ATC as needed for changes in operating conditions, while providing for unique modeling parameters of the areas. The SPP Transmission Provider calculations do not preclude any studies made by Transmission Owners in accordance with their individual tariffs, which may contain specific methodologies for evaluating transmission service requests.

Transfer capabilities are calculated for two different commercial business applications; a) for use as default values for Transmission Owners to post on their OASIS node for business under their transmission tariffs and b) for use by SPP in administering the SPP Open Access Transmission Tariff (SPP OATT).

The SPP utilizes a “constrained element” approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed “Flowgates”, used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using Flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (Flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes Therefore, the SPP Operating Reliability Working Group and the SPP Transmission Working Group will have the joint authority to modify the implementation of this Section of the Criteria based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP By-laws at the first practical opportunity, with the exception of response factor thresholds for short-term transmission service which may be approved for immediate implementation by the ORWG subject to subsequent review by the MOPC at the first practical opportunity. The response factor thresholds for short-term and long-term service are included in Appendix 9.

4.1 DEFINITIONS

4.1.1 Base Loading, Firm and Non-Firm (FBL & NFBL)

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load and impacts from existing OATT OASIS commitments.

4.1.2 Capacity Benefit Margin

The amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

4.1.3 Contractual Limit

Contractual arrangements between Transmission Providers that define transfer capability between the two.

4.1.4 Critical Contingency

Any generation or transmission facility that, when outaged, is deemed to have an adverse impact on the reliability of the transmission network.

4.1.5 Designated Network Resources (DNR)

Any designated generation resource that can be called upon at anytime for the purpose of serving network load on a non-interruptible basis. The designated generation resource must be owned, purchased or leased by the owner of the network load.

4.1.6 Emergency Voltage Limits

The operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a Critical Contingency.

4.1.7 Firm Available Transfer Capability (FATC)

The determined transfer capability available for firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff (OATT) or any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.8 First Contingency Incremental Transfer Capability (FCITC)

NERC Transmission Transfer Capability, reference document (May 1995) defines FCITC as:

> "The amount of power, incremental and above normal base transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:
>
> 1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,
> 2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission circuit, transformer or generating unit, and,
> 3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facilities loadings are within emergency ratings and all voltages are within emergency limits."

4.1.9 Flowgate

A selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage, stability and contractual system constraints to power transfer. The process of determining the reliability issues for which a Flowgate is representative of and by which a Flowgate is established is outlined in the Flowgate Determination section.

4.1.10 Line Outage Distribution Factor (LODF)

The percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service

4.1.11 Local Area Problem

A Transmission Owner may declare a facility under its control a Local Area Problem if it is overloaded in either the base case or contingency case prior to the transfer. If a member declares a facility a Local Area Problem, the member may neither deny transmission service nor request NERC Transmission Loading Relief for that defined condition.

4.1.12 Monitored Facilities

Any transmission facility that is checked for predefined transmission limitations.

4.1.13 Non-firm Available Transfer Capability (NFATC)

The determined transfer capability available for sale for non-firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff for any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.14 Normal Voltage Limits

The operating voltage range on the interconnected system that is acceptable on a sustained basis.

4.1.15 Open Access Transmission Tariff (OATT)

FERC approved Pro-Forma Open Access Transmission Tariff.

4.1.16 Operating Horizon

Time frame for which Hourly transmission service is offered. The rolling time frame is twelve to 36 hours with a 12 noon threshold. It includes the current day, and after 12 noon, the remainder of the current day and all hours of the following day.

4.1.17 Operating Procedure

Any policy, practice or system adjustment that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. If an Operating Procedure is submitted to the SPP in writing and states that it is an unconditional action to implement the procedure without regard to economic impacts or existing transfers, then the Operating Procedure will be used to allow transfers to a higher level.

4.1.18 Outage Transfer Distribution Factor (OTDF)

The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service

4.1.19 Participation Factor

The percentage of the total power adjustment that a participation point will contribute when simulating a transfer.

4.1.20 Participation Points

Specified generators that will have their power output adjusted to simulate a transfer.

4.1.21 Planning Horizon

Time frame beyond which Hourly transmission service is not offered.

4.1.22 Power Transfer Distribution Factor (PTDF)

The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.

4.1.23 Power Transfer Voltage Response Factor (PTVF)

The per unit amount that a facility's voltage changes due to a particular transfer level.

4.1.24 SPP Open Access Transmission Tariff (SPP OATT)

The Southwest Power Pool Regional FERC approved Open Access Transmission Tariff

4.1.25 Transfer Distribution Factor (TDF)

A general term, which may refer to either PTDF or OTDF – The TDF represents the relationship between the participation adjustment of two areas and the Flowgates within the system.

4.1.26 Transfer Test Level

The amount of power that will be transferred to determine facility TDFs for use in DC linear analysis.

4.1.27 Transmission Owner (TO)

An entity that owns transmission facilities which are operated under a FERC approved OATT.

4.1.28 Transmission Provider (TP)

An entity responsible for administering a transmission tariff. In the case of the SPP OATT, SPP is the Transmission Provider. An SPP member may be its own Transmission Provider if the member continues to sell transmission service under the terms of its own tariff.

4.1.29 Transmission User (TU)

Any entities that are parties to transactions under appropriate tariffs.

4.1.30 Transmission Reliability Margin (TRM)

The amount of Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

4.1.31 TRM multipliers (a & b)

"a"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Planning Horizon

"b"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Operating Horizon

4.2 CONCEPTS

4.2.1 Transfer Capability

Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission circuits (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). Transfer capability is also directional in nature. That is, the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

Some major points concerning transfer capability analysis are briefly outlined below:

1. **System Conditions** - Base system conditions are identified and modeled for the period being analyzed, including projected customer demand, generation dispatch, system configuration and base reserved and scheduled transfers.

2. **Critical Contingencies** - During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

3. **System Limits** - The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

Thermal and voltage transfer limits can be determined by calculating the First Contingency Incremental Transfer Capability. Stability studies may be performed by the Transmission Owners at their discretion. Any known stability limits, which are determined on a simultaneous basis, and all contractual limits will be supplied by each Transmission Owner in writing to the Transmission Provider and the TWG.

4.2.2 Available Transfer Capability

NERC Available Transfer Capability Definitions and Determinations, reference document (June 1996) states: "Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above

already committed uses."
SPP determines ATC as a function of the most limiting Flowgate of the path of interest. How limiting a Flowgate is to a path is based on two aspects: (1) The determined firm or non-firm Available Flowgate Capacity (FAFC or NFAFC) for that Flowgate, and (2) the TDF for which that Flowgate responds to power movement on the path under evaluation.

The common relationship between the identified limiting Flowgate and the path is the Transfer Distribution Factor (TDF). This is mathematically expressed as follows:

> **Firm ATC** = the firm Available Flowgate Capacity divided by the Transmission Distribution Factor
> (FATC = FAFC/TDF)
> of the associated path.
>
> Likewise,
>
> **Non-Firm ATC** = the non firm Available Flowgate Capacity divided by the Transmission Distribution Factor
> (NFATC = NFAFC/TDF)
> of the associated path.

Path ATC is determined by identifying the most limiting Flowgates to the path in question. Each Flowgate represents a potential limiting element to any path within a system. Therefore, each Flowgate with known Transfer Distribution Factor (TDF) can be translated into path ATC. However, the Flowgate that produces the most limiting path ATC is the key Flowgate for that path.

The calculation of path ATC using this method is based on the ratio of the TDF into the remaining capacity of a Flowgate, (non firm Available Flowgate Capacity or firm Available Flowgate Capacity). Once a group of potential limiting elements has been selected, then all values pertaining to ATC can be translated based on the TDF.

4.2.3 Response Factors

Response Factors are numerical relationships between key adjustments in the transmission system and specific transmission components being monitored. They provide a linear means of extrapolation to an anticipated end for which decisions can be made. The thresholds for several of the following response factors are listed in Appendix 9.

(1) **Transfer Distribution Factor** - The Transfer Distribution Factor (TDF) is a general term referring to either PTDF or OTDF. The relationship between adjustments in participation points associated with a specific path and the identified Flowgate in the system is the TDF. Depending on the Flowgate type, the TDF may specifically represent the response in the system to certain types of pre-identified system limitations as mentioned in the System Limitations section of the criteria.

(2) **Line Outage Distribution Factor** - The Line Outage Distribution Factor (LODF) is the percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

(3) **Power Transfer Distribution Factor** - The Power Transfer Distribution Factor (PTDF) is the percentage of a power transfer that flows through a facility or a set of facilities for a particular transfer when there are no contingencies. PTDF type Flowgates are used for representing Thermal, Voltage, Stability and Contractual Limitations. To be considered a valid limit to transfers, a PTDF Flowgate must have a PTDF at or above the applicable short-term or long-term threshold

(4) **Outage Transfer Distribution Factor** - The Outage Transfer Distribution Factor (OTDF) is the percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service. OTDF type Flowgates typically represent contingency based thermal limitations within the system. They can also be used to represent Stability

limitations. To be considered a valid limit to transfers, a Monitored Facility must have an OTDF at or above the applicable short-term or long-term threshold.

(5) **Power Transfer Voltage Factor** - The Power Transfer Voltage Factor (PTVF) is the per unit amount that a facility's voltage changes due to a particular transfer level. To be considered a valid limit to transfers, a Monitored Facility must have a PTVF at or above the applicable short-term or long-term threshold.

4.2.4 Transfer Capability Limitations

The electrical ability of the interconnected transmission network to reliably transfer electric power may be limited by any one or more of the following.

1. **Thermal Limits** - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission circuit ratings are defined in the SPP Rating of Equipment.

2. **Voltage Limits** - System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions of or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent The Normal Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis. The Emergency Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance. Voltage limits will be as specified in the Planning Criteria section of the SPP

Criteria: Regional Transmission Planning.

3 **Stability Limits** - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a disturbance. Specific Stability Limits Criteria is found in the SPP Criteria: Regional Transmission Coordinated Planning.

4. **Contractual Requirements**- Some Transmission Owners have contractual arrangements that contain mutual agreements regarding the power transfer available between them. These contractual arrangements have been approved by the appropriate regulatory agencies. The NERC Operating Policies inherently recognize contract requirements that may limit the power transfer between Transmission Owners. Some contract requirements are discussed in NERC Operating Policy 3 – Interchange.

The limiting conditions on some portions of the transmission network can shift among thermal, voltage, stability and contractual limits as the network operating conditions change over time

4.2.5 Invalid Limits

The procedures outlined in criteria may lead to identification of certain limiting facilities that are invalid. Reasons may include, but are not limited to:

- An invalid contingency generated as a generic single outage, which is not valid without the outage of other facilities.
- Incorrect ratings. Ratings will be corrected and the limiting transfer level recalculated.
- The rating used may be directional in nature (directional relaying) and may not be valid for the direction of flow.
- The limiting facility is the result of over-generation/under-generation at a participation point.
- The contingency is considered improper implementation of an operating procedure.
- The facility represents an equivalent circuit.

- The limiting facility is declared a Local Area Problem

Any limiting facility determined to be invalid due to modeling error that could be corrected must be corrected by the next series of seasonal calculations.

4.2.6 Flowgates

Flowgates are selected power transmission element groups that act as proxies for the power transmission system capable of representing potential thermal, voltage, stability and contractual system limits to power transfer. There are two types of Flowgates;

- OTDF Flowgate; Composed of usually two power transmission elements in which the loss of one (contingency facility) can cause the other power transmission element (monitored facility) to reach its emergency rating.
- PTDF Flowgate; Composed of one or more power transmission elements in which the total pre-contingency flow over the flowgate cannot exceed a predetermined limit. Either with the power transmission system intact or with a contingency elsewhere, the Flowgate can be selected to represent a thermal, voltage, stability or contractual limit.

Once a set of limiting elements have been identified, as potential transfer constraints, they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the Total Flowgate Capacity (TFC) of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce.

To the extent that the impedance network models are similar with similar participation patterns, the same Flowgates can be monitored in other network models for purposes of evaluating the impact of additional transactions on the network. Of course, each network model will be subtly different therefore it is important that engineering judgment is exercised regarding the validity of applying existing Flowgates to a new network model.

4.2.7 Total Flowgate Capacity (TFC)

The Flowgate and its Total Flowgate Capacity are pre-defined A Flowgate is intended to limit the amount of power allowed to flow over a defined element set. This TFC may reflect several possible types of system limitations as described in the Limitations Section.

For OTDF Flowgates representing thermal overloads, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility.

For PTDF Flowgates, the TFC represents the total amount of power that can flow over a defined element set under pre-contingency conditions.

Again, limit types could be.

1) Thermal limits under normal operating conditions or linked contingency events,
2) Voltage limits under normal operating conditions or linked contingency events,
3) Stability limits under normal operating conditions or linked contingency events, or
4) Contractual limits.

Flowgates are selected based on the impacts of power transfer in an electrical network and will be evaluated on a regular basis and revised as needed to ensure thorough representation of the system they are representing.

Each Flowgate represents a possible limitation within a network and in itself has a Flowgate rating (TFC) and an Available Flowgate Capacity (AFC) which can be translated via the path response factor (TDF) to a path Available Transfer Capability (path ATC) for any path

4.2.8 Flowgate Capacity

4.2.8.1 Total Flowgate Capacity (TFC)

A Flowgate acts as proxy to path transfer limitations. This allows additional transfer capability on a path based on the additional loading that can be incurred. The determination of additional loading that can be incurred on a Flowgate begins first with the determination of the maximum loading that can be allowed on a PTDF Flowgate or on the monitored facility of an OTDF Flowgate during its associated contingency. This maximum loading is termed Total Flowgate Capacity (TFC).

4.2.8.2 Available Flowgate Capacity (AFC)

The available capacity on a Flowgate for additional loading for new power transfers is determined by taking the Total Flowgate Capacity (TFC) and removing the Flowgate Base Loading (FBL) and the Impacts due to existing system commitments and any transmission margins.

AFC = TFC – FBL – Impacts of existing commitments – transmission margins

4.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC)

Path ATC is classified as firm or non-firm. This distinction is made when determining the Available Flowgate Capacity (AFC) remaining for path ATC. AFC is classified as firm or non-firm depending on the types of existing commitments considered for Impacts. This is realized in the formula for Available Flowgate Capacity:

(AFC = TFC – FBL – Impacts of existing commitments – transmission margins).

4.2.9 System Impacts

4.2.9.1 Impacts of Existing Commitments

In order to simultaneously account for impacts of all commitments to all paths at any given instant in time, it is necessary to devise a system that allows for fluctuation in the number of and the magnitude of system commitments on each path within an acceptable amount of time, for the purpose of providing transmission service in a competitive manner.

Existing transmission commitments beyond those modeled as native load and related generation commitments can be found on the OASIS. However, before impacts of OASIS posted reservations can be calculated, they must first be interpreted – carefully examined for peculiar individual characteristics. Due to the nature of the OASIS and the rules therein, posted reservations sometimes require interpretation as to their actual value to apply toward the transmission network.

The following are examples of evaluations that are performed:

- Recognize and adjust for duplicate reservations by multiple providers to complete one transaction.
- Adjust for reservations that may have changed status or have been replaced by another reservation, including renewals and redirects.
- Check for proper reflection of capacity profiles of reservations.
- Distinguish status and class of reservations such as Study, Accepted, Confirmed, Firm, and Non-Firm status to determine their proper impact level.

4.2.9.2 Positive Impacts

The scope of "Impacts of existing commitments" in the formula for AFC incorporates both the calculated positive impacts and counter impacts of non-firm and firm service commitments. A positive impact is determined as having the effect of increasing the loading on a Flowgate in the direction of the Flowgate. Positive impact types are sorted into those resulting from firm and non-firm service commitments. To determine firm or non-firm Available Flowgate Capacity, the appropriate impacts are applied to make up the "Impacts of existing commitments" in the above formula. Additionally, counter impacts are considered depending on firm or non-firm determinations.

4.2.9.3 Counter Impacts

Counter impacts are those impacts due to transfers that act to relieve loading on limiting elements. Counter impact types are sorted into those resulting from firm and non-firm service commitments. These flows are not traditionally accepted as valid under the pretense that any reservation that may cause such a loading relief is not actually doing so until it has been scheduled. To consider counter-flows in transfer capability studies is to assume a high probability of scheduling

4.2.10 Monitored Facilities

During the Flowgate determination process those facilities monitored for pre-defined limiting conditions. Mandatory Monitored Facilities, for use in these calculations, are all facilities operated at 100 kV and above and all interconnections between Transmission Providers. Other facilities operated at lower voltage levels may be added to the Monitored Facilities list at the discretion of the Transmission Providers or Transmission Owners.

In defining Flowgates, the Monitored Facilities are those components of a Flowgate that remain in service following the defined contingency.

4.2.11 Critical Contingencies

Those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multi-terminal lines, or generating units. All interconnections of an area will be considered Critical Contingencies, regardless of voltage level as will the largest generating unit in the area.

4.3 RELIABILITY MARGINS

Transmission margins are very important to the reliability of the interconnected network in an Open Access environment. The NERC "Available Transfer Capability Definitions and Determination Reference Document" defines Transmission Reliability and Capacity Benefit margins (TRM, CBM).

When using Flowgates as a means to represent a system's constraints, it is necessary to translate reliability margins, TRM and CBM, to a unique TRM and CBM for each Flowgate. Margins are the required capacities that must be preserved for the purpose of moving power between areas during specific emergency conditions. Since a margin is a preservation of transfer capacity, the margin itself will have an impact on the most limiting element between the two areas for which it is reserved.

All studies for the purpose of assessing TRM and CBM will only include generation units located within the transmission system for which the Transmission Provider is responsible. These generation units may also include those not specifically designated to serve network load connected to transmission systems within the Transmission Provider system. However, the method by which a Transmission Provider is to determine TRM and CBM shall not vary from that described herein with the exception of assessing facilities located outside of SPP regional structure/bounds.

4.3.1 Transmission Reliability Margin (TRM)

TRM on a Flowgate basis is that amount of reserved Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The following factors shall be considered by SPP in the determination of TRM.

- Load Forecast

Transmission Providers will forecast hourly load for the next seven days for all applicable control areas.

Beyond seven days, Transmission Providers will project a demand based on seasonal peak load models for all applicable Transmission Owners. These load levels will be the projected peaks for the time frame for which the forecast applies.

- Variations in Generation Dispatch

Variations to generation patterns constitute a viable concern. Generation dispatch in near-term models will be based on real-time snapshots of network system conditions. For the longer-term horizons, whenever possible, generation dispatch information provided by generation owners will be applied to the ATC calculations. However, it is recognized that longer-term dispatch is probably unknown to the generation controlling entities themselves except for base-load and must run type units.

- Unaccounted Parallel Flows

Parallel flows can be an issue if pertinent data to the ATC calculations are not shared among the transmission providers and those transactions that have multiple wheeling parties are not identified. Provisions in the SPP OATT have reduced the impacts of these transactions within SPP and between SPP and other regions.
Transmission Owners of facilities that are impacted by unaccounted parallel flows or variations in dispatch may request additional TRM for their impacted Flowgates from the TWG. Such requests must be in writing, must document the parallel flow impacts or the variance in historical dispatch, and be accompanied by analysis or documentation supporting the additional TRM requirements. The TWG shall have the authority to grant or reject requests for the additional TRM requests.

- SPP Operating Reserve Sharing

The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. To that end, TRM on the Flowgates will provide enough capacity to withstand the impact of the most critical generation loss to that facility. All generation contingencies will be simulated by the Operating Reserve Sharing algorithm to determine the highest impact on each Flowgate. This capacity will be included in TRM.

- Counter Flow Impacts

Another factor to consider in the SPP TRM process is that for the planning horizon, which is primarily next day and beyond, the counter flow impacts of reservations on the Flowgates are removed with the exception of Designated Network Resources. This provides an inherent margin in the calculation which along with the constant TRM provided by the reserve sharing allocation, is a proxy for the generation variation.

4.3.2 TRM Coordination

The TRM specified on a Flowgate represents a transmission margin that the transmission system needs to maintain a secure network under a reasonable range of uncertainties in system conditions As such it is not necessarily an import or export quantity specifically The Automatic Operating Reserve Sharing portion is determined by centralized Regional study based on the SPP Operating Reserve Sharing Criteria. Any additional TRM may be requested by the Flowgate owner/s, subject to review by the SPP TWG.

4.3.3 TRM Availability for Non-firm Service

To maximize transmission use to the extent reliably possible, Transmission Providers may sell TRM on a non-firm basis. The 'a' and 'b' multipliers facilitate this purpose in the calculations. However, a contingency or long-term outage to a high impact unit may result in the curtailment of non-firm schedules and displacement of non-firm reservations sold within the TRM.

4.3.4 TRM Calculation Frequency

The Operating Reserve Sharing portion of the TRM will be determined annually for each season (Spring, Summer, Fall, Winter). This process is outlined in the SPP Criteria under Operating Reserves and the Operating Reserve Share Program Procedures. Flowgate owner requests for additional TRM may be submitted at any time for consideration at the next TWG meeting. The submittal should include justification and rational in writing for the requested additional TRM. The TWG shall have authority to reject or grant such requests.

4.3.5 Capacity Benefit Margin (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin. As a normal practice, default values for CBM will be zero for calculations of ATC for some or all of the following reasons:

- the existing level of internal capacity margin of each member is adequate
- historical reliability indicators of transmission strength of the SPP area
- Open Access transmission usage environment allows greater purchasing options

Flowgate owner requests for additional CBM may be submitted at any time for consideration at the next TWG meeting. The submittal should include written justification and rational for the requested additional CBM. The TWG shall have authority to reject or grant such requests.

4.4 FLOWGATE AND TFC DETERMINATION

The Flowgates used by SPP to administer the Regional Tariff serve as a proxy of the transmission system. It is therefore essential to the reliable operation of the transmission system for the set of Flowgates to adequately represent the transmission system

4.4.1 Flowgate Updates

Updating the list of Flowgates is a continual process. Flowgate additions and deletions and changes in TFC are the result of studies, analyses, and operating experience of SPP and its member Transmission Owners. At any time during the year, the owner of transmission facilities may require that a set of facilities be used as a Flowgate to protect equipment or maintain system reliability, regardless of the ownership of that set of facilities. SPP will update the Flowgate list as needed. The responsibility for reviewing and monitoring the list will be shared between the individual Transmission Owners, the TWG, the Operating Reliability Working Group (ORWG) and the SPP staff. Updating the Flowgate list may or may not require running a study. If the Transmission Owner is to perform a study, they are responsible for gathering accurate information from neighboring Transmission Owners. The following requirements apply when adding a Flowgate to the list:

- Transmission Owners may add OTDF Flowgates, provided that the contingency is valid, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility, and no operating procedures apply to that Flowgate.

- Transmission Owners may add PTDF Flowgates, provided that it is a single facility Flowgate, the TFC is equal to the normal rating of the single facility, and no operating procedures apply to that Flowgate.

- All other Flowgates proposed by Transmission Owners must have TWG and ORWG approval. The Reliability Authority can provide interim approval until the TWG and ORWG can convene to assess the request. Examples of such Flowgates are PTDF Flowgates with two or more elements, OTDF Flowgates with three or more elements, or Flowgates involving operating procedures

There may be times when significant topological changes occur during operations that create unexpected loadings on facilities not explicitly modeled as Flowgates. During these conditions, the Reliability Coordinator will work with the Transmission Owner(s) to develop a commercial Flowgate representative of the conditions present. Any such additions will be analyzed at the next Flowgate evaluation to determine if they should remain in the permanent list of Flowgates.

4.4.2 Annual Review

In addition to the continual studies and analyses, the Flowgate list will also be reviewed annually by the TWG using seasonal power flow models. This annual assessment will be performed following the January SPP Model Development Work Group (MDWG) release of each year's load flow cases. This review is intended to serve as a tool by which the TWG, the Transmission Owners, and the SPP may assess the adequacy of the existing list of Flowgates and thereby recommend necessary additions, deletions, and TFC changes. In order to accomplish this assessment, the process herein described will be used to identify the most limiting elements for a variety of transfer directions. Although transfer values will be involved in this process, this process is not intended to produce any viable ATC values for use commercially or otherwise. Rather, ATC values are determined as described in the "ATC Calculation Procedures" section.

4.4.2.1 Power Flow Models

The power flow models to be used in the process will be based on the models developed annually by the SPP MDWG. Application of the models will use the following season definitions. The Summer Model will apply to June through September, the Fall Model will apply to October and November, the Winter Model will apply to December through March and the Spring Model will apply to April and May. Each of these seasonal models developed will represent peak models. In addition, for the summer season only, a Summer Shoulder Case representing approximately an 85% load level will be used in the determination process.

Prior to the start of the review all SPP Transmission Owners will submit a list of changes to SPP to adjust the models. These changes should be such that the power flow models used to review the Flowgate list represent the seasonal loads, transmission system configuration, generation dispatch, and transactions that each Transmission Owner expects will occur during actual seasonal operations. The changes will be submitted to SPP in a common format as outlined in the SPP Load Flow Procedure Manual.

Model changes and parameters for Transmission Owners outside of SPP will be coordinated through the NERC regional councils.

4.4.2.2 Parameters supplied by the Transmission Owners

In order to simulate a transfer, certain parameters must be known. These include the participation points of MW increase/decrease and the participation factor of these points. These items will be supplied to SPP by the Transmission Owners.

Participation points for exports will primarily be points of generation within the sending area. Generators that are off-line may be turned on to participate in a transfer. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The participation points used for export will be consistent for all transfer directions.

The participation points for imports will primarily be points of generation reduction within the receiving area. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The generation reduction should be based on economics, operating constraints or other criteria as specified by the Transmission Owner. The participation points used for import will be consistent for all transfer directions.

Other parameters that must be supplied by the Transmission Owners include the following:

- A contingency list including all critical single contingencies (both transmission and generation) as well as multi-terminal facilities.
- All contingencies suspect of causing voltage limitations and the transfers for which they should be studied.
- Any additional facilities below 100 kV to be monitored.
- High and low voltage limits for system and/or individual buses.
- All Contractual Requirements.

4.4.2.3 Default Parameters

The following parameters will be used in the event that a Transmission Owner does not submit the area specific parameters:

- For exports, the participation points will include all on-line generating facilities in the model with unused generating capacity available.
- The export participation factors will be the amount of unused generating capacity at each point divided by the sum of the unused generating capacity at all export participation points. (i.e., PMAX-PGEN).
- For imports, all on-line generators will be decreased prorated by their capable generation (i e., PGEN-PMIN).
- Transfer directions will be a set of all commercial paths.
- Exports from merchant power plants will be considered in the determination of Flowgates
- The transfer test levels are specified at the time of the ATC calculations, and are determined by SPP staff.
- All facilities 100 kV and above will be included in the contingency list and the monitored facility list. In addition, the largest unit within the area will be included in the contingency list.
- Voltage limits will be as specified in Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

4.4.2.4 Voltage Limits

Voltage limits are network and system dependent. Each Transmission Owner will submit an acceptable set of Normal Voltage Limits and Emergency Voltage Limits to be applied for the purpose of Flowgate and TFC determination.

4.4.2.5 Linear Analysis and AC Verification

SPP will perform DC linear analysis studies estimating the import or export ability of the identified commercial paths using a combined linear evaluation of the network models with a follow up AC verification of a minimum of the first three valid operational limitations. Specific AC analysis will also be performed on any specified contingency/transfer combinations noted as voltage limiting contingencies. Monitored Facilities, Contingency Facilities and Participation Points will be implemented as described in the "Parameters Supplied by the Transmission Owners" section or "Default Parameters" section as applicable.

4.4.2.6 Operating Procedures

Operating Procedures are available and may increase the Total Flowgate Capacity of a Flowgate when implemented. Implementation of any available Operating Procedures will be done using a full AC solution to determine the correct limit to be placed on a Flowgate. Any operationally increased Total Flowgate Capacities established will be so noted.

4.4.2.7 Identification of Flowgate Changes

TWG will review the FCITC results of the power flow models and selected paths and identify whether any Flowgates should be added, removed, or changed to better represent the SPP transmission system.

A minimum of the first three valid FCITC limitations to each path will be AC verified. When all paths have been evaluated, the TWG will review the AC verification results and, where needed, the linear results for consideration as potential Flowgates.

Typically, new Flowgates should be either OTDF Flowgates with a TFC representing the total amount of power that can flow during a contingency without violating the emergency rating of the monitored facility or single facility PTDF Flowgates with a TFC equal to the normal rating of the single facility. In situations involving operating procedures the TFC may be higher than the facility ratings.

The TWG will then determine any needed changes to the existing list of Flowgates. The number of times elements appear as one of the most limiting components for transfers, the rank in the list of most limiting elements, and the TDF level will be the primary factors considered in making the determination. Flowgates can also be developed to represent identified Voltage Limitations and Contractual Requirements.

4.4.2.8 Review and Coordination with Transmission Owners

Each SPP Transmission Owner will have the option of naming a representative to review the results of the Flowgate review or deferring to the TWG finalization of the results. Summary sheets of all interfaces or paths calculated will be communicated to the representatives for review. All data will be made available for review upon request. The results will be approved by the TWG before being reported.

The Transmission Owner should review the TWG proposed Flowgate changes and consider their own operating experience and study results. Any modifications to the TWG proposed changes should be returned to the TWG. Further dialog and justification may be required of a Transmission Owner if the TWG has concerns about their modifications.

TWG will draft a final Flowgate list, incorporating the comments of the Transmission Owners. The Transmission Owners should approve any additions, deletions, or changes to the Flowgate list.

4.4.2.9 Initiating Interim Review of Flowgate List

Operational condition changes, especially status changes of EHV transmission facilities and large generators, may warrant a partial or full evaluation of the list of Flowgates. A review may also be necessary due to multiple schedules being implemented causing parallel flows.

Transmission Owners will have access to copies of the SPP models and all relevant data used for the annual review. Transmission Owners may at any time request a re-run of the Flowgate evaluations. The Transmission Owner requesting the re-run shall provide their reasons for requesting the re-run to the TWG for consideration. Should the TWG deem a re-run necessary, the SPP staff will perform the additional evaluation.

4.4.3 Dispute Resolution

If there is a dispute concerning a Flowgate, the questioning party must contact SPP and the Transmission Owner(s) involved to resolve the dispute.

Examples of reasons for disputing a Flowgate may include:

- The contingency used for the Flowgate is not valid.
- There is an operating procedure that corrects the violation that is not being properly taken into account.
- An operating procedure is being taken into account in an improper manner yielding an incorrect TFC.

If the parties involved do not reach agreement on the selected Flowgates, the SPP TWG will review all of the arguments Additional analyses will be performed if necessary. SPP TWG will then make a final determination. If a party still wishes to dispute the Flowgate, the SPP Dispute Resolution policy described in Section 2 of the SPP By-laws may be initiated.

4.4.4 Coordination with Non-SPP Members

Flowgates involving transfers on interfaces and paths between SPP Transmission Owners and non-SPP Transmission Owners will be coordinated by the parties involved and the TWG.

4.4.5 Feedback to SPP Members

The SPP staff shall maintain a table of all Flowgates on the SPP OASIS. The table shall include all Flowgate data, which are applicable, including the Flowgate name, monitored facility, contingency facility, Flowgate rating, TRM, CBM, a and b multipliers, LODF, the TDF basis for the Flowgate (OTDF or PTDF), and the TDF cutoff threshold. This table shall be updated with any new information on or before the first of each month.

4.5 ATC CALCULATION PROCEDURES

The determination of ATC via Flowgates utilizes proxy elements to represent the power transmission network. This process depends on the selected Flowgates to act as pre-determined limiting constraints to power transfer The process by which ATC will be determined when using the Flowgate proxy technique incorporates the Definitions and Concepts within this Criteria.

Determination of ATC via Flowgates adheres to the following approach:

- establishes a network representation (power flow model)
- identifies potential limits to transfer (thermal, voltage, stability, contract)
- determines response factors of identified limits relative to transfer directions (TDF)
- determines impacts of existing commitments (firm, non-firm)
- applies margins (TRM, CBM, a & b multipliers)
- determines maximum transfer capabilities allowed by limits and applied margins (ATC, FATC, NFATC)

4.5.1 ATC Calculation and Posting Timeframes

To assist Transmission Providers with Short Term service obligations under FERC Order 888 and 889, SPP will calculate the monthly path ATC for the upcoming 16-months for all potential commercial paths for Transmission Providers in the SPP Region. This data will be posted for use in evaluating the SPP OATT requests and provided on a monthly basis to the Transmission Providers in adequate time to post the information on OASIS nodes by the 1st of each month.

Hourly, Daily and Weekly ATC shall be calculated on a daily basis and posted at the time of run. SPP will also provide commercial path conversions to any individual providers needing that information to administer their own tariff. Hourly ATC shall be calculated for 12 to 36 hours ahead depending on time of day. SPP has a firm scheduling deadline at 12:00 noon of the day prior to start. At this point all firm schedules are known and the hourly non-firm request window opens for the next day. At this point SPP will calculate hourly ATC for HE 14 of the current day through HE 24 of the next day. This process continues dropping the current hour each resynchronization until 12:00 noon the next day when the cycle starts again. Again SPP will provide commercial path conversions for any SPP provider that needs them for posting on their own OASIS nodes.

4.5.2 Power Flow Models

The monthly calculation of Flowgate based ATC will be made using rolling seasonal models that produce an update for the upcoming sixteen month service window (12 month multi-month service + 4 months advance notice). For example, the required data update for January of any year will yield data for January thru December plus the next January, February, March and April of the following year. The necessary seasonal models will be selected from the approved SPP MDWG set to represent this time frame. Any known system changes/corrections to these models will be included. SPP will routinely calculate ATC for the upcoming 16-month service window. Monthly models will be updated/developed from the latest seasonal models to represent individual months for the purpose of capturing operational conditions that may be unique from other monthly models.

4.5.3 Base Loading, Firm and Non-Firm (FBL & NFBL)

Model base flows provide the basis for which to begin determination of Available Flowgate Capacity However, there are many transactions within the monthly models that are duplicated on the OASIS. A record of the network model flows of each Flowgate as found in the solved network models will be used as a beginning point to account for impacts of base case transactions and existing commitments. The impacts on Flowgates due to transactions outside the purpose of representing designated Network Resource exchange will be removed by applying the TDF factors determined to each transaction identified in the base case. In addition to adjusting the model flow in this manner, positive and counter impacts of existing OASIS commitments will be applied according to the type of Base Loading (Firm or Non-Firm) under consideration. In non-firm Base Loading, 50% of Counter Impacts resulting from firm Confirmed reservations will act to reduce the overall Base Loading figure. This process will establish the base loading expected with each control area serving its firm Network Load.

4.5.4 Transfer Distribution Factor Determinations (TDF)

For export and import participation points all on-line generators, unless otherwise denoted (e.g., nuclear units), will be scaled prorated by their machine base (MBASE). TDF data will be calculated for all commercial paths using the most current participation data, ATC models and Flowgate list on a monthly basis.

4.5.5 Existing Commitments and Netting Practices

Existing commitments resulting from Confirmed, Accepted and Study reservations on the SPP OATT OASIS nodes will be considered and accounted for in the determination of Available Flowgate Capacity. Accounting for the impact of existing commitments is a key part of the process for determining which new transfers will be allowed, unlike the TLR implementation process which involves determining which existing transfers must be curtailed. Therefore, unlike TLR implementation which requires a minimum TDF threshold, all positive impacts from existing commitments must be applied without using a minimum TDF threshold. Impacts from these commitments will be applied according to the future time frame of which they are applicable. These time frames are discussed below:

4.5.5.1 Yearly Calculations (whole years, starting 60 days out)

A Yearly transmission service request is defined as a service request with a duration of greater than or equal to 1 year in length. The evaluation of Available Transfer Capability for this service type is performed utilizing solved network models with existing OASIS commitments figured in as net area interchange values. In addition to monitoring Flowgates, standard N-1 contingency analyses will be performed to study the impact of yearly transmission requests on the transmission system The long-term threshold is shown in Appendix 9 and is applied to all elements above 60kV.

4.5.5.2 Monthly Calculations (months 2 through 16)

The impacts of OASIS reservations that are Confirmed, Accepted and in Study mode will be applied to each Flowgate according to the TDF values determined. All positive impacts on a Flowgate due to these types of reservations decrease ATC. 100% of counter flow impacts due to reservations supplying Designated Network Resources are allowed to increase ATC. For non-firm service, up to 50% of the counter-flows due to all firm Confirmed reservations will be allowed on a Flowgate. The combined positive impacts and counter flow impacts will be added to the base flows to determine Available Flowgate Capacity for the Monthly calculation.

4.5.5.3 Daily and Weekly Calculations (Day 2 through 31)

For Daily and Weekly calculations, composite area interchange values will be determined by integrating all OASIS Confirmed and Accepted reservations into projection models. Base flows
will be determined by the projection models. The impacts of OASIS reservations that are in Study mode will be applied to each Flowgate according to the TDF values determined. Positive impacts on a Flowgate due to Confirmed reservations that are not expected to be scheduled based on actual historical scheduling data will be removed and allowed to increase firm Available Flowgate Capacity. Counter flow impacts of Confirmed reservations that are expected to be scheduled based on actual historical scheduling data will be allowed to increase firm Available Flowgate Capacity. Up to 50% of the counter flow impacts due to all firm Confirmed reservations will be allowed to increase non-firm Available Flowgate Capacity.

4.5.5.4 Hourly Calculations (Day 1)

These calculations are for hourly non-firm service only. All known schedule information from NERC Electronic-tags will be applied to base flow calculations. These schedules determine base interchange values. Since these are expected schedules, all counter flow impacts are allowed in this calculation. OASIS reservation information is not considered for determination of existing impacts in this calculation.

4.5.6 Partial Path Reservations

Requests made on individual Transmission Provider's tariffs require two or more reservations to complete a transaction resulting in a partial path reservation. The SPP OATT offers service out of, into and across SPP and between SPP members with a single reservation. For transmission service under the SPP OATT, only reservations with valid sources and sinks are allowed. However, to avoid double accounting of Flowgate and system impacts due to duplicate reservations documented on Transmission Provider OATT OASIS nodes from partial path reservations, necessary means will be incorporated to recognize these related reservations and determine the correct singular impacts.

4.5.7 ATC Adjustments Between Calculations

ATC will be adjusted following receipt of any valid SPP OASIS node reservation. The requested capacity will be multiplied by the TDF on all affected Flowgates and the resulting amounts will be subtracted from each Flowgates' ATC and posted to the OASIS.

4.5.8 Coordination of Transmission Commitments with Neighboring Organizations

Coordination of dispatch information, Confirmed firm and non-firm system commitments from neighboring regions, RTO's, ISO's etc. will be conducted as appropriate to each type of ATC being determined to establish the most accurate system representation of base flows and generation profiles. External reservations may be retrieved from other OASIS sites or locations designated by neighboring Transmission Providers.

4.5.9 Margins

Identified TRM and CBM will be applied to each Flowgate as described in the Reliability Margins section.

4.5.10 ATC Determination

The following equations are used in ATC determination:

4.5.10.1 Firm Base Loading (FBL)*, **:

- Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm OASIS Commitments, Confirmed, Accepted and Study) – (100% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments for DNR only)

4.5.10.2 Non-Firm Base Loading (NFBL)*, **:

- Non-Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm and Non-Firm OASIS Commitments, Confirmed, Accepted and Study) – (up to 50% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments)

4.5.10.3 Firm Available Flowgate Capacity (FAFC):

- Firm Available Flowgate Capacity = (Total Flowgate Capacity) – (TRM) – (CBM) – (Firm Base Loading)

4.5.10.4 Non-Firm Available Flowgate Capacity (NFAFC, Operating Horizon):

- Non-Firm Available Flowgate Capacity, Operating Horizon = (Total Flowgate Capacity) – (b*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.5 Non-Firm Available Flowgate Capacity (NFAFC, Planning Horizon):

- Non-Firm Available Flowgate Capacity, Planning Horizon = (Total Flowgate Capacity) – (a*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.6 Firm Available Transfer Capability (FATC):

- Firm ATC = Most limiting value from associated Flowgates = Min {Firm Available Flowgate Capacity/TDF of appropriate path}

4.5.10.7 Non-Firm Path Available Transfer Capability (NATC, Operating Horizon):

- Non-Firm ATC, Operating Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Operating Horizon/TDF of appropriate path}

4.5.10.8 Non-Firm Available Transfer Capability (NFATC, Planning Horizon):

- Non-Firm ATC, Planning Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Planning Horizon/TDF of appropriate path}

* Applicable pre-emption requirements of lower priority service types will be considered when evaluating requests for transmission service.

** Impacts resulting from queued Study reservations will be applied according to priority when evaluating requests for transmission service.

SPP will calculate the ATC for each of its Transmission Providers on their direct interconnections (either physical interconnections or by rights to a line) and any interface or path requested by a Transmission Provider to fulfill its obligations under FERC Order 889. The

ATC for requested interfaces or paths will be calculated only if requested by the Transmission Provider obligated to post the interfaces or paths.

4.5.11 Annual Review of ATC Process

The SPP TWG will conduct an annual review of the Regional ATC determination process including TRM and CBM to assess regional compliance with NERC requirements, regional reliability needs and functionality toward SPP Transmission Owners and Users. This review will be held at the same time as the Flowgate Evaluation process. The applicable long-term TRM is listed in Appendix 9.

SPP will conduct a survey of the Transmission Owners and Users and the results will be published on the SPP website. Concerns that are identified from the survey will be forwarded to the appropriate SPP Committee.

4.5.12 Dialog With Transmission Users

Transmission Users may contact the TWG with any concerns regarding this criterion, its implementation, or the resulting ATC values. The concerns should be in writing and sent to the chair of the TWG The chair will then draft a written response to the Transmission User containing either an answer or a schedule for when such an answer can be provided. If the Transmission User is not satisfied, the concerns can be sent to the chair of the Markets and Operations Policy Committee.

5.0 RELIABILITY COORDINATION CENTER

Continuous coordinated operation of the bulk electric system is essential to maintain reliable electric service to all customers. Reliability coordination procedures are established herein for sharing of operating information and around-the-clock coordination of normal and emergency operating conditions to secure the reliability of the bulk electric system.

5.1 Information Exchange

Control areas shall share operating data as defined in Appendix 7 to the SPP Criteria and approved by the ORWG. Non-Control Areas shall share operating data deemed necessary for assessment of regional reliability. Generator data for all generating units whose size is greater than or equal to the smaller of 10 MW or 5% of the reporting Control Area peak load, transmission circuit data for all interconnections, and transmission facilities operated at 60 kV or greater shall be automatically shared. This data shall be made available to the Reliability Authority and any other entity with immediate responsibility for interconnection reliability. The Reliability Authority shall obtain a signed code of conduct from entities receiving such data ensuring that the data will not be used for marketing purposes. Necessary operational data shall be made available on an interregional telecommunications network to support the requirements in this Criteria. This near real-time data will be exchanged as specified in Appendix 7 and approved by the ORWG.

5.2 Reliability Coordination

5.2.1 Member Responsibilities

Transmission Operators shall determine System Operating Limits (SOLs), as defined in Criteria 14 2.4, in conjunction with transmission owners. SOLs will be provided for facilities that comprise flowgates and any other facilities as determined by the Transmission Operator in conjunction with the transmission owners. The Transmission Operator shall inform the Reliability Coordinator of changes to any SOL as specified in Appendix 7 and notify the Reliability Coordinator of any SOL violations.

Control Areas shall notify the Reliability Coordinator of current or foreseen operating conditions that may adversely affect interconnection reliability. Scheduled outages of critical transmission facilities shall be approved by the Reliability Coordinator Scheduled outages of all other facilities greater than 60 kV shall be coordinated with the Reliability Coordinator. The Operating

Reliability Working Group shall be responsible for identifying those facilities classified as critical. Non-control areas shall notify their Control Area of current or foreseen operating conditions that may adversely affect interconnection reliability. Scheduled transmission outages shall be coordinated with their Control Area

5.2.2 Operatiing Reliability Working Group

The Operatiing Reliability Working Group shall be responsible for policy oversight of implementation and on-going reliability coordination processes and services as described in this Criteria. This working group shall make regular reports to the Engineering & Operating Committee.

5.2.3 SPP Staff

The SPP Staff shall be responsible for development and administration of reliability coordination processes and services as described in this Criteria, including budgeting and staffing requirements.

5.2.4 Reliability Authority Responsibilities

On a continuous around-the-clock basis, the SPP Reliability Authority shall be responsible for the following activities:

5.2.4.1 Daily Reliability Assessment

a. Monitor the collection of real-time operating information, schedules and daily forecasts from control areas as specified in Appendix 7.
b. Develop and use an operational model to assess reliability and adequacy of the electric system, including; ability to handle more probable contingencies and remain within operating criteria, anticipating line loading problems, and determining the adequacy of operating reserve.
c. During conditions where system reliability is threatened, notify and work with control areas in determining appropriate control action.

5.2.4.2 Daily Operational Coordination

a. Monitor, coordinate and grant permission for bulk transmission equipment maintenance.
b. Manage the SPP Open Access Same-Time Information System node and ATC calculation.

c. Monitor the NERC Hot line and disseminating information.

d. Initiating time error corrections.

5.2.4.3 Compliance Monitoring

a. Assess and report regional compliance with NERC operating criteria, including; area interchange error, CPS1, CPS2, DCS, frequency response, and inadvertent.

b. Coordinate bilateral inadvertent energy accounting and payback.

5.2.4.4 Emergency Procedure Implementation

a. Monitor and coordinate implementation of Operating Reserve Criteria.

b. Monitor and coordinate implementation of Transmission Loading Relief Criteria.

c. Monitor and coordinate implementation of Load Shedding and Restoration Criteria.

d. Monitor and coordinate implementation of Black Start Criteria.

e. Issue short supply advisories.

f. Issue weather advisories.

5.2.4.5 Interregional Coordination

a. Coordinate normal and emergency operations with other Reliability Authorities.

b. Authoritatively act on behalf of SPP Members to resolve interregional issues.

5.2.5 Other Reliability Authority Responsibilities

The SPP Reliability Authority shall be responsible for the following activities:

a. Confirm transactions during periods of Transmission Loading Relief as outlined in Criteria.

b. Direct implementation of Black Start procedures as outlined in Criteria.

c. Implement Transmission Loading Relief Procedures as required.

5.2.6 Reliability Authority Performance Standards

The SPP Reliability Authority shall have the following performance standards.

a. The SPP Reliability Authority shall act in accordance with Good Utility Practice including NERC Policies and SPP Criteria, shall not order SPP members to take any action that would not be in accordance with Good Utility Practice, and shall allow SPP members to take any actions required by Good Utility Practice.

b. The SPP Reliability Authority shall not take any action, or direct SPP members to take any action, which would be in violation of any lawful regulation or requirement of any governmental agency.
c. The SPP Reliability Authority shall carry out its responsibilities in at least as prompt and efficient a manner as that required by Good Utility Practice including NERC Policies and SPP Criteria.
d. The SPP Reliability Authority shall monitor adherence to its directives and report non-compliance to the appropriate SPP organizational group.
e. The SPP Reliability Authority shall be a certified system operator as defined by related SPP Criteria.

The SPP Reliability Authority shall sign an appropriate standards of conduct document ensuring appropriate protection of competitively sensitive information.

6.0 OPERATING RESERVE

6.1 Purpose

In the continuous operation of the electric power network, Operating Capacity is required to meet forecasted load, including an allowance for uncertainty, to provide protection against equipment failure and to provide adequate regulation of frequency and Balancing Authority Area tie line power flow. Operating Reserves are needed to regulate load changes and to support an Operating Reserve Contingency without shedding firm load or curtailing Firm Power Sales.

This Criteria establishes standard terminology and minimum requirements governing the amount and availability of Contingency Reserves to be maintained by the distribution of Operating Reserve responsibility among members of the SPP Reserve Sharing Group.

A purpose of this Criteria is to ensure a high level of reliability in the SPP Reserve Sharing Group by assuring that there is available at all times capacity resources that can be used quickly to relieve stress placed on the interconnected electric system during an Operating Reserve Contingency. Another purpose of these Criteria is to utilize efficiently the operating reserve resources of the SPP Reserve Sharing Group.

This Criteria describes practices to be followed by all SPP Reserve Sharing Group members to ensure prompt response to Operating Reserve Contingencies. The methods prescribed by this Criteria to jointly activate Contingency Reserve are intended to ensure that the combined area control error (ACE) of the SPP Reserve Sharing Group is quickly reduced by the Reserve Sharing Group simultaneously scheduling assistance soon after an Operating Reserve Contingency.

6.2 Definitions

6.2.1 Balancing Authority

NERC defines a Balancing Authority as "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time." A Balancing Authority is required to meet all NERC Reliability Standards, SPP Criteria and the policies of the NERC Regional Reliability Council of which they are a member

6.2.1.1 Balancing Authority Area

NERC defines a Balancing Authority Area as "The collection of transmission, generation and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

6.2.2 Balancing Authority Daily Peak Load Obligation

Balancing Authority Daily Peak Load Obligation is the peak hour load plus Firm Power sales minus Firm Power purchases during the peak hour for all entities within the Balancing Authority Area.

6.2.3 Operating Capacity

Operating Capacity is the dispatchable capability claimed for any generating source, which will be used for supplying Operating Reserve. Operating Capacity shall include capacity purchases that can be used to supply the buyer's Operating Reserves minus capacity sales that cannot be used to supply the seller's Operating Reserves. Operating Capacity shall recognize any temporary de-ratings, proven loading rates, starting times and equipment limitations including transmission-operating limits. This capacity is not intended to be the tested seasonal net capability; instead it is the normal operating rating of a generator on a given day.

6.2.4 Operating Reserve

Operating Reserve is the sum of Regulating Reserve and Contingency Reserve.

6.2.4.1 Regulating Reserve

Regulating Reserve is an amount of Spinning Reserve responsive to AGC, which is sufficient to provide normal regulating margin. The Balancing Authority Area minimum Regulating Reserve is equal to an amount necessary to maintain compliance with control performance standards while scheduling all Contingency Reserves to other Balancing Authority Areas

6.2.4.2 Contingency Reserve

Contingency Reserve is that Operating Capacity that can be produced and applied to reduce ACE to meet the NERC Disturbance Control Standard (DCS) following the Operating Reserve Contingency. Contingency Reserve is the sum of Spinning Reserve and Ready Reserve

6.2.5 Spinning Reserve

Spinning Reserve is that unloaded Operating Capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation. The Spinning Reserve allocated to any generating unit shall not exceed the amount of capacity increase that will be realized by prime-mover governor action due to a drop in frequency to 59.5 Hertz (less than or equal to 16.7% of unit capability at a 5% droop setting). At least half of the Contingency Reserve shall be Spinning Reserve.

6.2.6 Ready Reserve

Ready Reserve is that amount of Operating Capacity or the equivalent, some or all of which may not be connected to the interconnected network but which can be connected and fully applied to meet the NERC DCS requirements, such as any or a combination of the following:

a. The amount of Operating Capacity connected to the bus that will not be realized by prime-mover governor action. The realization of this capacity may require the governor speed level to be reset.

b. That portion of fast starting generating capacity at rest, such as hydroelectric, combustion turbines, and internal combustion engines as prime movers that can be started and synchronized.

c. Operating Capacity that can be realized by increasing boiler steam pressure, by removing feedwater heaters from service, and/or by decreasing station power use.

d. Operating Capacity and contingency reserve, provided firm transmission has been purchased, being held available under contract by another Balancing Authority above its own operating reserve requirements and available on call

e. Interruptible or curtailment of loads under contract.

f. Power deliveries that can be recovered provided a clear understanding exists between the transacting parties to avoid both parties crediting their respective operating reserves by this transaction.

g. Generating units operating in a synchronous condenser mode.

h. Interruptible pumping load on pumped hydro units

i. Operating Capacity made available by voltage reduction. The voltage reduction shall be made on the distribution system and not on the transmission system.

j. Operating Capacity that can be fully applied from a change in the output of a High Voltage Direct Current terminal.

6.2.7 Assistance Period

Assistance Period is that time frame when any SPP Reserve Sharing Group member receives Contingency Reserve assistance from other SPP Reserve Sharing Group members. The Assistance Period will normally not exceed 60 minutes. The SPP Operating Reliability Working Group will set the ending time for Assistance Period and may change the length of the Assistance Period.

6.2.8 Group

A Group is defined for each member of the SPP Reserve Sharing Group on a daily basis to include itself and all other members with which there exists contractual interchange agreements, which include provisions for the exchange of Operating Reserve energy. Each member of the Reserve Sharing Group may include any other member,,with which they can directly schedule interchange transactions, within their group as long as both members agree.

6.2.9 Contingency Area

The Contingency Area is defined as the Balancing Authority Area suffering an Operating Reserve Contingency.

6.2.10 Assisting Areas

The Assisting Areas are defined as the other Balancing Authority Areas in the SPP Reserve Sharing Group, which are called upon to supply Operating Reserves to the Contingency Area.

6.2.11 Daily Load and Capability Report

The Daily Load and Capability Report is a report which shall be completed by each Balancing Authority This report shall include actual and forecasted operating information.

6.2.12 Firm Power

Firm Power shall mean electric power which is intended to be continuously available to the buyer even under adverse conditions; i.e., power for which the seller assumes the obligation to provide capacity (including SPP defined capacity margin) and energy. Such power shall meet standards of reliability and availability as that delivered to native load customers. Power purchased shall only be considered to be Firm Power if firm transmission service is in place to the load serving member for delivery of such power. Firm Power does not include "financially firm" power.

6.2.13 Other Extreme Conditions

Other Extreme Conditions include but are not limited to the.

- **a.** Interruption of firm transmission service, or
- **b.** An inability to use prescheduled firm transmission service due to transmission loading relief, or
- **c.** When a Balancing Authority requires assistance to prevent shedding firm load or Firm Power sales, or
- **d.** When a Balancing Authority is unable to maintain its Operating Reserves.

6.2.14 Operating Reserve Contingency

An Operating Reserve Contingency is defined as the sudden and complete loss of a generating unit, sudden partial loss of generating capacity, loss of a capacity purchase which a Balancing Authority is unable to replace, or an Other Extreme Conditions.

6.2.15 Reserve Sharing Group

NERC defines a Reserve Sharing Group as "A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the areas become a Reserve Sharing Group."

6.3 Minimum Daily Reserve Requirement

The Operating Reliability Working Group will set the Minimum Daily Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group will maintain a minimum first Contingency Reserve equal to the generating capacity of the largest unit scheduled to be on-line. Normally, the SPP Reserve Sharing Group will add an additional Operating Reserve Requirement over and above its Regulating Reserve and first Contingency

Reserve equal to one-half of the next largest generating unit scheduled to be on-line within the SPP Reserve Sharing Group each day (second Contingency Reserve). A Balancing Authority's Minimum Daily Requirement is equal to a prorated amount of the SPP Reserve Sharing Group Minimum total Daily Contingency Reserve Requirement (first and second Contingency Reserves) based on the previous day's actual Balancing Authority Daily Peak Load Obligation. A Balancing Authority's Minimum Daily Requirement shall be no less than two (2) MW.

Under emergency operating conditions, the Minimum total Daily Contingency Reserve Requirement may be raised to the generating capability of the two largest generating units scheduled to be on-line upon the concurrence of the chair or vice chair of either the Markets and Operations Policy Committee or the Operating Reliability Working Group.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total first Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

6.4 Procedures

All SPP Reserve Sharing Group members shall participate in this procedure to jointly activate Contingency Reserve.

6.4.1 Normal Daily Operation

a. Each Balancing Authority shall complete the Daily Load and Capability Report. Based on the information contained in this report, the Contingency Reserve Requirement for the next day shall be calculated and notification distributed. Previous annual maximum data shall be used in reserve responsibility calculations for members who fail to report daily information. A Balancing Authority may elect to enter an amount of Contingency Reserve Requirement on the daily report, which, if in excess of its minimum requirement as calculated by the SPP computer communication system, shall be available for allocation during Assistance Periods. No portion of this additional reserve is required to be spinning.

b. Each Balancing Authority's Operating Reserve shall be distributed so as to ensure that it can be utilized without exceeding individual element ratings, transfer limitations, or a unit's capability to apply the reserve to meet the NERC DCS requirements.

c. Each Balancing Authority shall schedule Operating Capacity and firm obligations so its requirements for Operating Reserve are met at all times.

d. Energy associated with Ready Reserve, except Assistance Schedules, may be sold with the understanding that it is recallable to meet the NERC DCS requirements. The buyer shall therefore maintain resources to support the withdrawal of this energy in addition to meeting its Operating Reserve Requirement

e. Generating capacity associated with the required Spinning Reserve shall not be sold unless allocated during an Assistance Period.

f Each Balancing Authority may contract with another Balancing Authority to provide part or its entire Operating Reserve obligation, provided the Balancing Authority accepting this additional Operating Reserve obligation maintains the Operating Reserve obligation of both Balancing Authorities and the firm transmission service required to deliver Operating Reserve energy is obtained.

g. When a Balancing Authority foresees it will be unable to provide its Minimum Daily Reserve Requirement with available resources because load is greater than anticipated, forced outages or other limitations, it shall obtain Operating Capacity and firm transmission service. Such capacity shall not be from another Balancing Authority's Minimum Daily Reserve Requirement.

6.4.2 Contingency Operation

These procedures shall be implemented immediately following the occurrence of an Operating Reserve Contingency of the type and magnitude as follows.

- A complete loss of a generator rated at 50 MW or greater, or
- A partial loss of generating capacity of 75 MW or more, or
- A partial loss of generating output of 50 MW or more or
- A loss of a capacity purchase of 50 MW or more, or
- Any "Other Extreme Conditions" event.

These procedures may be implemented immediately following the occurrence of an Operating Reserve Contingency of any type and magnitude,as system conditions warrant, by the

Contingency Area. These procedures are to be implemented in a non-discriminatory manner.

a. Immediately following an Operating Reserve Contingency, the Contingency Area shall report the occurrence via the SPP computer communication system. This report shall contain a description of the contingency; any capacity lost, the net MW output lost due to the contingency and any MW amount of Contingency Reserve being carried on the contingency unit. For those generating units whose station auxiliaries do not decrease to essentially zero or increase after a unit trip, gross MWs lost shall be used instead of net MWs lost. The operating owner of jointly owned generating units shall be responsible for reporting outages and the MW amount lost by each owner.

b. Within the constraints described in this Criteria, allocation magnitudes shall be determined and notices distributed to the members of the Reserve Sharing Group

c. The maximum amount assigned to any Balancing Authority for any single Operating Reserve Contingency shall not exceed its Spinning Reserve requirement unless the contingency reserve requirement exceeds the available Spinning Reserve of the SPP Reserve Sharing Group The additional responsibility shall be allocated to other members of the SPP Reserve Sharing Group until the total Spinning Reserves are exhausted. Any remaining responsibility shall be allocated to the SPP Reserve Sharing Group by a similar procedure as the initial allocation out of the total Ready Reserve. The Operating Reliability Working Group may adjust for any single member or for all members the maximum amount allocated.

d. The Assistance Schedule becomes part of each Assisting Area's scheduled net interchange and shall therefore be reflected in its ACE. The schedule shall be implemented at a zero time ramp rate immediately following allocation notification. If obvious and significant errors exist in assistance schedules, the Contingency Area system operator shall dictate appropriate corrective action during the Contingency Period, and notify the SPP.

e. Assisting Areas shall immediately acknowledge receipt of the allocation notice via the SPP computer communication system. If a Contingency Area fails to receive acknowledgment from an Assisting Area, the SPP Reliability Coordinator shall notify the Assisting Area of the assistance schedule.

f. After the implementation of the allocation, the Contingency Area and Assisting Areas shall report to the SPP, when their ACE returned to zero or it's pre-contingency level whichever is achieved first.

g. The Contingency Reserve Requirement of each Balancing Authority Area involved in the Assistance Period shall be updated to reflect the reduction of responsibility until the end of the Assistance Period.

h. All allocations shall be rounded to the nearest whole MW with a minimum of 2 MW and the smallest amount of energy to be allocated shall be one MWH.

i. After the contingency notification has been completed, the Contingency Area shall promptly make arrangements to replace the energy requirement created by the Operating Reserve Contingency (including its Contingency Reserve Allocation) prior to the end of the Assistance Period. The Contingency Area shall make a reasonable effort to purchase capacity and firm transmission service after utilization of its own resources

j. If assistance is needed by the Contingency Area for a period of time longer than the initial Assistance Period, then this becomes an Other Extreme Condition and shall be reported as a separate contingency.

k. Each transmission provider shall immediately notify the SPP of the loss of transmission interconnection capability affecting its interchange transfer capability. The SPP shall update Group assignments for use during subsequent Assistance Periods. Each transmission provider is responsible for notifying the SPP once the contingency loss in the interchange transfer capability has been restored so that Group assignments can be updated.

l. For each reportable contingency (as defined by the Operating Reliability Working Group), the Contingency Area and Assisting Areas will send to SPP an electronic data file in a SPP specified format that records ACE, Frequency Deviation, Net Tie Deviation, and Net Interchange for 10 minutes prior to until 30 minutes after the contingency within two days of the SPP request for this data. If electronic data is not available, this data will be supplied on the NERC required charts.

6.4.3 Subsequent Contingencies

In the event that a subsequent Operating Reserve Contingency occurs during a period when assistance is already in progress, the same procedures shall be followed to allocate responsibility for the additional Operating Reserve Contingency.

6.4.4 Assistance Reports

Energy and transmission service reports shall be issued following the Assistance Period. These reports shall be used as verification of associated energy schedules and transmission service reservations. The Operating Reliability Working Group shall distribute monthly summary reports of Other Extreme Conditions activity for use.

SPP Staff will report to NERC quarterly the performance of the SPP Reserve Sharing Group. Performance will be calculated based on the data that Balancing Authorities provide and any additional data required for each reportable contingency. At a minimum, reportable contingencies will be of a magnitude between 80% and 100% of the capacity of the largest generating unit scheduled to be on-line within the SPP each day The Operating Reliability Working Group may lower the 80% factor in order to provide a more realistic picture of the performance of the SPP Reserve Sharing Group.

6.4.5 Other Extreme Conditions Events

The SPP Reserve Sharing Group member seeking assistance through Other Extreme Conditions must submit a written report to the SPP within 2 business days of the event The written report will describe the operating conditions that precipitated the request for assistance. If a Balancing Authority's only other choice was to shed firm load or Firm Power sales, the Balancing Authority must demonstrate this condition by taking the following steps, where appropriate, before requesting Other Extreme Conditions:

a. All generation capable of being on-line in the time frame of the generation deficiency must be on-line, including quick start and peaking units regardless of the cost.

b. All firm and non-firm purchases have been made without regard to cost.

c. All non-firm sales have been curtailed within the provisions of the sale agreement.

d. Interruptible load has been curtailed where contractual restrictions have been met or the interruptible load is considered as part of the Balancing Authority's Operating Reserves.

e. Have implemented all other load reductions programs that can be implemented within the time frame of the generation deficiency (i.e. voltage reductions, public appeals, etc.).

Any member not having their full Operating Reserves shall enter an Other Extreme Conditions for the amount of the deficiency.

Other Extreme Conditions shall be investigated as required by the SPP Operating Reliability

Working Group to ensure compliance with SPP Criteria and NERC Reilability Standards.

6.5 Compensation for Assistance

6.5.1 Energy Charge

The charge for energy assistance delivered by Assisting Areas under the application of this Criteria shall be determined by interchange agreements between the members involved in the Reserve Sharing Group.

6.5.2 Accounting

All compensation for energy associated with the application of this Criteria shall be handled by contractual agreements and standard accounting procedures being utilized by the SPP Reserve Sharing Group members. All energy billing shall take place between SPP Reserve Sharing Group members and shall not involve the SPP computer communication system or the SPP Staff.

6.5.3 Transmission Service

All compensation for transmission service shall be in accordance with the appropriate transmission service tariffs. The SPP staff shall be responsible for all billings for transmission service provided under the SPP Regional Transmission Tariff. The individual transmission provider shall be responsible for all billings under the transmission provider's transmission tariff. It shall be the SPP staff's responsibility to provide the required transmission service information to the transmission provider for all transmission service under an individual transmission provider's transmission tariff.

6.6 Responsibilities

6.6.1 Balancing Authorities

It shall be the responsibility of each Balancing Authority to observe the policies and procedures contained herein; maintaining Operating Reserve, ensuring connectivity to the SPP computer communications system, reporting daily information, identifying and reporting an Operating Reserve Contingency within its Balancing Authority Area, acknowledging schedules and supplying assistance to members of the SPP Reserve Sharing Group.

6.6.2 Operating Reliability Working Group

In order to review the adequacy in SPP Reserve Sharing Group, reports shall be compiled and distributed by the SPP for review by members and the Operating Reliability Working Group. These reports shall contain compliance information and a summary of Assistance Period events.

7.0 SYSTEM PROTECTION EQUIPMENT

7.1 Disturbance Monitoring Equipment

'Disturbance Monitoring Equipment' (DME), as the term is used in this Section, refers to equipment such as Digital Fault Recorders (DFR), Sequence of Events Recorders, Phase Angle Monitors and other devices connected to the power system for the purpose of monitoring performance of the system. This equipment is used to capture data during disturbances defined as (i) any perturbation to the power system, or (ii) the unexpected change in the power system that is caused by the sudden loss of generation, transmission or interruption of load. Digital fault recorders are capable of producing fault records, consisting of instantaneous values of power system quantities collected many times per cycle, for a specific period of time. Disturbance monitoring devices collect and store (a) "fault data" from a line or equipment trip for abnormal conditions, or (b) "disturbance data" for power system performance swings or deviations outside of a predefined operating range (frequency, voltage, current, power, transients, etc.). Sequence of Events Recorders (SER) capture and time stamp events in the sequence in which they occur. The facility owner should be responsible for interpreting the information from SER's due to the equipment specific and detailed nature of these records. Typically, SER's record the sequence of breaker operations needed for higher-level event reconstruction and analysis. Information provided by SER's may be obtained from other devices such as fault recording equipment, SCADA, or other real time computer records.

7.1.1 Minimum Technical Requirements

Disturbance Monitoring Equipment, as a minimum, must be capable of producing time stamped event records (some pre-fault and some post-fault data) including waveforms for voltages and currents as well as power circuit breaker position indications. Sequence of Events Recorders may not be required as long as an appropriate monitoring device provides breaker indication. All new DME as required in 7.1.2 and 7.1.4 shall be synchronized to the National Institute of Standards and Technology time. All 230kV and above substations with DFRs that have the capability to be upgraded with time synchronization shall be upgraded by December 31, 2005 to use the National Institute of Standards and Technology synchronized time.

DME shall be capable of recording 5 events of not less than 30 cycles in duration with a sampling rate of 64 samples per cycle. Event data shall be retrievable for a period of not less than 72 hours. A minimum of three (3) cycles of pre-disturbance data shall be recorded with each event. DME shall record, at a minimum, the quantities listed below

1) One set of voltages for each operating voltage at 100 KV and above in a substation. A set of voltages shall consist of each phase voltage waveform. If potential devices are not required for protection or metering purposes at a particular voltage level, then this particular voltage level need not be monitored.
2) For all lines, either three phase current waveforms or two phase current waveforms and neutral (residual) current waveform.
3) For all autotransformers, current waveform for three phases and either neutral/residual current waveform or current waveform in delta windings.
4) Status – circuit breaker trip circuit energization.
5) Status – carrier transmit/receive if carrier relaying is used.
6) Date and time stamp.
7) For equipment installed after 1-1-2007, frequency, MW and MVARS shall be recorded or be able to be derived from collected information. Sampling rate minimum for this data shall be one sample per cycle.

Regarding event triggering thresholds, quantities as derived from SPP or members' studies, when available, shall be used in lieu of those defined below. If none are clearly defined from load flow and stability studies, then the following requirements shall be used as a guide:

1) Phase current greater than or equal to 150% of the equipment rating.
2) Neutral (residual) current greater than or equal to 20% of the rating of the equipment
3) Voltage excursions greater than or equal to 10% from operating range of equipment.

7.1.2 Required Location for Monitoring Equipment

Disturbance Monitoring Equipment will be required at all new EHV substations, operated at 345kV or higher, and all new generating stations of 400 MVA or greater placed in service after January 1, 2002 In addition, any new substation placed in service after January 1, 2002 containing six (6) or more lines operating at 100 KV and above will be required to have DME. However, when additional lines placed in service after January 1, 2002 are added to an existing substation that results in six (6) or more total lines, then DME shall be required for monitoring all elements within the substation as defined in 7.1.1. These requirements may be waived at

SPP's discretion, if DME is already located at an adjacent substation. The number, type and location of disturbance monitoring equipment will normally be the responsibility of the facility owners based on recommendations by the owners' studies and this criteria. Information about installations will be provided by the facility owners to the SPP in accordance with NERC Standards and maintained in a database by the SPP staff for a period of at least three (3) years. The SPP System Protection and Control Working Group (SPCWG) shall monitor this database. The Transmission Assessment Working Group and Operating Reliability Working Group will review the database to recommend that equipment with adequate capabilities, including digital fault recorders, be installed at critical locations throughout the system as determined in power flow and dynamic stability studies.

7.1.3 Requirements for Testing and Maintenance Procedures

Each facility owner shall have a documented maintenance program in place to test or the means to periodically check the functionality of the Disturbance Monitoring Equipment in service. These tests shall be done based on the manufacturers' recommendation or, if less frequent, to maintain reliable operation. For newer DME's with self-monitoring, having SCADA reporting for a DME failure, and with successful downloading of events occurring at least annually, then such activity and application shall satisfy the testing and maintenance procedure requirements. A facility owner that tests on a less frequent basis than the manufacturer's recommendation shall provide written justification for such a change, if requested by SPP or NERC. The facility owner will be responsible for maintaining and providing required maintenance data for its facilities for a minimum of three (3) years. Each facility owner will provide updates to the SPP or NERC upon request

7.1.4 Periodic Review of Disturbance Monitoring Equipment

SPP members shall maintain a list of substations where Disturbance Monitoring Equipment is located for generation and transmission facilities including those designated as being critical by the Transmission Assessment and Security Working Groups. The facility owner shall be responsible for providing required data on a form developed by the System Protection & Control Working Group and supplied by SPP. Each facility owner will provide updates to the SPP upon request. The SPP staff will maintain and update the Disturbance Monitoring Equipment database. The Transmission Assessment and Operating Reliability Working Groups will review the database annually for additions and changes, specifically checking for equipment as recommended in Section 7.1.2. The SPCWG will update, if necessary, this System Protection Equipment Criteria every three (3) years

7.1.5 Requests for Disturbance Data and Retention Requirements

SPP shall function as a requesting agent and clearing house for the collection of data on an as needed basis when the request is not from an SPP member. Facility owners shall provide requested equipment lists and disturbance data within 30 business days with a copy of the requested information forwarded to the SPP. SPP shall provide installation and reporting requirements to other regions and NERC within five (5) business days SPP members and NERC staff may also formally request data from SPP members with a copy of the request forwarded to the SPP. Such requests will be considered to be a request from SPP staff.

A narrative description of each disturbance, pursuant to the requirements of SPP Criteria 11 addressing System Disturbance Reporting, to be provided by the facility owner shall include, at a minimum, a brief description of the event as identified on a form supplied by SPP. Additional items that shall be included are the cause of the incident, its consequences, service interrupted, corrective actions taken and any other additional actions that may be required beyond the point in time when the analysis is completed to include when these actions will be completed. Attachments shall be provided including relevant information from the DME that substantiates the determination of cause(s) of the disturbance. This information shall include all quantities based on the equipment requirements specified in 7.1.1, Minimum Technical Requirements. Facility owners shall retain disturbance data for a period of not less than one (1) year in a common format to the extent possible given the different manufacturers and types of equipment. However, the units of the data and source such as line, transformer and generator terminal shall be clearly identifiable in a consistent, time-synchronized format.

7.2 Transmission Protection Systems

7.2.1 Introduction

The goal of Transmission Protection Systems (TPS) is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network to preserve electric system integrity. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure, misoperation of the protection system, and the need to maintain overall system reliability. All reviews of facilities as included in Criteria 7.2 shall be for those operated at 100kV or above.

7.2.2 Protection System Review

7.2.2.1 Assessment Of System Performance

The transmission or protection system owners shall provide an assessment of the system performance results of simulation tests of the contingencies in Table I of Standard I.A. (NERC Planning Standard). These assessments should be based on existing protection systems and any existing backup or redundancy protection systems to determine that existing transmission protection schemes are sufficient to meet the system performance levels as defined in NERC Standard I.A. and associated Table I. Therefore, the relative effects on the interconnected transmission systems due to a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters. All non-compliance findings shall be documented including a plan for achieving compliance. These assessments should be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems within 30 days of the request.

7.2.2.2 Reviews Of Components And Systems

The owner shall conduct periodic reviews of the components and systems that make up the transmission protection system to assure that components and systems function as desired to minimize outages. All non-compliance findings, as a result of this review, shall be documented including a plan for achieving compliance. These reviews are to be completed as system changes dictate, or more frequently as needed based on misoperations as identified in Criteria 7.2.4. The reviews should include, but not be limited to, the following items:

1) Review of relay settings.
2) Current carrying capability of all components (Lines, CTs, breakers, switches, etc.).
3) Interrupting capability of all components (breakers, switches, fuses, etc.).
4) Breaker failure and transfer trip schemes.
5) Communications systems used in protection.

Models used for determining protection settings should take into account significant mutual and zero sequence impedances The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance. Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered. Protection system applications and settings should not normally limit transmission use. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible. Communications systems used in protection should be either continuously monitored or alarmed, or automatically or manually tested.

7.2.3 System Redundancy

Transmission Protection Systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I (NERC). Each Transmission or Protection System Provider shall develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, SPP, and those entities responsible for the reliability of the interconnected transmission systems, on request Where redundancy in the protection systems (due to single protection system component failures) is necessary to meet the system performance requirements (of the I.A. Standards on Transmission Systems and associated Table I), the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations Breaker failure protections need not be duplicated.

Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault while maintaining performance requirements. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition. When two independent protection systems are required, dual circuit breaker trip coils should be considered. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

7.2.4 Monitoring, Analysis And Notification Of Misoperations

Each Transmission or protection system owner shall have a process in place for the monitoring, notification, and analysis of all transmission protection trip operations Any of the following events constitute a reportable TPS misoperation:

1) Failure to trip – Any failure of a TPS to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device.
2) Slow Trip – A correct operation of a TPS for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intends.
3) Unnecessary Trip During a Fault – Any relay initiated operation of a circuit breaker during a fault when the fault is outside the intended zone of protection.
4) Unnecessary Trip Other Than Fault – The unintentional operation of a TPS which causes a circuit breaker to trip when no system fault is present. This may be due to vibration, improper settings, load swing, faulty relay, or human error.
5) Failure to Reclose – Any failure of a TPS to automatically reclose following a fault if that is the intent.

Misoperations at lower voltages that cause an outage of a transmission component, operated at 100kV or higher, shall be reported. An operation of a TPS that only has an effect on a non-transmission component operated at less than 100kV need not be reported. Documentation of all protection trip misoperations shall be provided to SPP and NERC within five (5) business days of the request. Each facility owner shall document that it has fully complied with its process for monitoring, notification, and analysis of all TPS trip operations. It shall also provide consistent documentation of all TPS trip misoperations, indicating the cause and those corrective actions that have been or will be taken. The facility owner will be responsible for providing documentation of misoperations on a form supplied by SPP. When requested,